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IEA Wind Task 25

Hannele Holttinen, Peter Meibom, Antje Orths, Frans van Hulle, Bernhard Lange, Mark O'Malley, Jan Pierik, Bart Ummels, John Olav Tande, Ana Estanqueiro, Manuel Matos, Emilio Gomez, Lennart Söder, Goran Strbac, Anser Shakoor, João Ricardo, J. Charles Smith, Michael Milligan & Erik Ela

Design and operation of power systems with large amounts of wind power

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Final report, IEA WIND Task 25, Phase one 2006–2008

Hannele Holttinen, VTT, Finland
Peter Meibom, Risø-DTU; Antje Orths, Energinet.dk, Denmark
Frans van Hulle, EWEA
Bernhard Lange, ISET, Germany
Mark O'Malley, UCD, Ireland
Jan Pierik, ECN; Bart Ummels, TU Delft, Netherlands
John Olav Tande, SINTEF, Norway
Ana Estanqueiro, INETI; Manuel Matos, INESC; João Ricardo, REN, Portugal
Emilio Gomez, University Castilla La Mancha, Spain
Lennart Söder, KTH, Sweden
Goran Strbac, Anser Shakoor, DG&SEE, UK
J. Charles Smith, UWIG, USA
Michael Milligan & Erik Ela, NREL, USA

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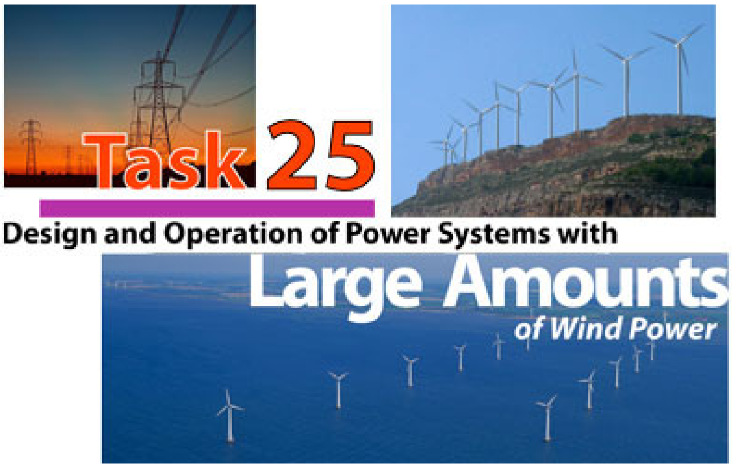
VTT, Bergsmansvägen 5, PB 1000, 02044 VTT
tel. växel 020 722 111, fax 020 722 7001

VTT Technical Research Centre of Finland, Vuorimiehentie 5, P.O. Box 1000, FI-02044 VTT, Finland
phone internat. +358 20 722 111, fax +358 20 722 7001



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Keywords wind energy, grid integration, wind power, balancing, capacity credit

Abstract

There are already several power systems coping with large amounts of wind power. High penetration of wind power has impacts that have to be managed through proper plant interconnection, integration, transmission planning, and system and market operations. This report is a summary of case studies addressing concerns about the impact of wind power's variability and uncertainty on power system reliability and costs. The case studies summarized in this report are not easy to compare due to different methodology and data used, as well as different assumptions on the interconnection capacity available. Integration costs of wind power need to be compared to something, like the production costs or market value of wind power, or integration cost of other production forms. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels.

Several issues that impact on the amount of wind power that can be integrated have been identified. Large balancing areas and aggregation benefits of large areas help in reducing the variability and forecast errors of wind power as well as help in pooling more cost effective balancing resources. System operation and working electricity markets at less than day-ahead time scales help reduce forecast errors of wind power. Transmission is the key to aggregation benefits, electricity markets and larger balancing areas.

From the investigated studies it follows that at wind penetrations of up to 20 % of gross demand (energy), system operating cost increases arising from wind variability and uncertainty amounted to about 1–4 €/MWh. This is 10 % or less of the wholesale value of the wind energy.

With current technology, wind power plants can be designed to meet industry expectations such as riding through voltage dips, supplying reactive power to the system, controlling terminal voltage, and participating in system operation with output and ramp rate control. The cost of grid reinforcements due to wind power is very dependent on where the wind power plants are located relative to load and grid infrastructure. The grid reinforcement costs from studies in this report vary from 0 €/kW to 270 €/kW. The costs are not continuous; there can be single very high cost reinforcements. There can also be differences in how the costs are allocated to wind power.

Wind generation will also provide some additional load carrying capability to meet forecasted increases in system demand. This contribution can be up to 40 % of installed capacity if wind power production at times of high load is high, and down to 5 % in higher penetrations and if local wind characteristics correlate negatively with the system load profile. Aggregating larger areas benefits the capacity credit of wind power.

State-of-the-art best practices in wind integration studies include (i) capturing the smoothed out variability of wind power production time series for the geographic diversity assumed and utilising wind forecasting best practice for the uncertainty of wind power production (ii) examining wind variation in combination with load variations, coupled with actual historic utility load and load forecasts (iii) capturing system characteristics and response through operational simulations and modelling (iv) examining actual costs independent of tariff design structure and (v) comparing the costs and benefits of wind power.

Preface

A R&D Task titled "Design and Operation of Power Systems with Large Amounts of Wind Power" was formed in 2006 within the "IEA Implementing Agreement on the Co-operation in the Research, Development and Deployment of Wind Turbine Systems" (http://www.ieawind.org) as Task 25. This R&D task will collect and share information on the experience gained and the studies made on power system impacts of wind power, and review methodologies, tools and data used. The results of the first 3-year period is reported in this report. The work will continue with a second 3-year period.

The following countries and institutes have been involved in the collaboration (TSO is Transmission System Operator):

- Denmark: Risø-DTU; TSO Energinet.dk
- EWEA (European Wind Energy Association)
- Finland: VTT Technical Research Centre of Finland (Operating Agent)
- Germany: ISET; TSOs RWE and E.ON Netz
- Ireland: SEI; UCD; ECAR; TSO Eirgrid
- Norway: SINTEF; Statkraft
- Netherlands: ECN; TUDelft
- Portugal: INETI; TSO REN; INESC-Porto, IST
- Spain: University Castilla La Mancha
- Sweden: KTH
- UK: Centre for Distributed Generation & Sustainable Electrical Energy
- USA: NREL; UWIG.

The Task started with producing a state-of-the-art report on the knowledge and results so far, published in VTT Working Papers series in 2007. In the state-of-the-art report, as well as in this report, a summary of only selected, recently finished studies is presented. The Task has also started the work of developing guidelines on the recommended methodologies when estimating the system impacts and the costs of wind power integration.

Credits and Acknowledgements

Finland: The national project in Finland consisted of work at VTT and Technical University of Helsinki TKK. Professor Liisa Haarla is acknowledged of her comments to the report. At VTT, Bettina Lemström and Sanna Uski-Joutsenvuo have provided comments to the text.

Portugal: The studies mentioned in sections 5.5.1 and 5.5.2 were performed by the “Centro de Energia Eléctrica” of the Departament of Electrothecnic and Computer Engineering of the “Instituto Superior Técnico” (IST) (Technical University of Lisbon), under contract with the Portuguese TSO, REN SA. The work referred in section 5.5.1 was coordinated by Professor Rui de Castro and the research and technical staff was constituted by Fernando Batista (IST) with the participation of J. Medeiros Pinto, António Pitarma and Tiago Rodrigues (REN, SA). The study of section 5.5.2 was coordinated by Professor J.P. Sucena Paiva (IST) and João Ricardo (REN, SA) and the research and technical staff was constituted by the Professors J. Ferreira de Jesus, Rui G. Castro, Pedro A. Flores Correia and the students Luís G. Vaz de Carvalho and Rui M. de Matos Pires (IST) and, from REN, SA, Reis Rodrigues, João Moreira and Bruno Nunes. The study mentioned in section 5.5.3, held by Red Eléctrica de España, SA (the Spanish TSO) with the participation of REN, SA, was performed by Luis Ímaz Monforte, Juan Manuel R. Garcia, Fernando Soto Martos, Francisco J. Rodríguez-Bobada, Sergio M. Villanueva (REE, SA) and, for the contribution of REN, SA, João Ricardo, Reis Rodrigues, João Moreira and Bruno Nunes. The data that enabled to construct Figures 2-b and the Portuguese contribution to Fig. 6, was kindly made available by the Portuguese renewable utility, ENERSIS, S.A. The Portuguese Advisory Group to IEA Wind Task 25 would like to thank Prof. António Sá da Costa, Mr. Mattos Parreira and Mr. Rui Maia to give the conditions for that Portuguese contribution. The work presented in Section 5.6, refers to Project RESERVAS which involved INESC Porto (a R&D institute) and the System Operators of Portugal (REN) and Spain (REE), within their joint medium and long term planning activities related to MIBEL (the Iberian electricity market). In developing the project, INESC Porto had the support of Universidade de Itajubá (Brazil) and worked in close collaboration with REN and REE teams that were responsible for the specification of the project objectives, model approval and analysis of the results.

Spain: Study (REE/REN 2006) was performed by a working group involving Red Eléctrica de España (REE) (Spain), Rede Eléctrica Nacional (REN) (Portugal), Comisión Nacional de la Energía (Spain) the Spanish Wind Energy Association (Spain). Among others, it was carried out by REE (Luis Ímaz Monforte, Juan Manuel R. Garcia, Fernando Soto Martos, Francisco J. Rodríguez-Bobada and Sergio M. Villanueva) and REN (João Ricardo, Reis Rodrigues, João Moreira and Bruno Nunes). Comments and assistance provided by Luis Coronado (REE), Alberto Ceña and Ángeles Mora (Spanish Wind Energy Association) and Venancio Rubio (Iberdrola S.A.) are also gratefully acknowledged.

Sweden: Reported studies have been performed by KTH (M. Amelin, J. Matevosyan, L. Söder, M. Olsson), Vattenfall Research and Development (U. Axelsson, R. Murray, V. Neimane, M. Brandberg, N. Broman, F. Carlsson) and Svenska Kraftnät (A. Danell, F. Norlund).

USA: The studies reported in this task have been conducted by a number of organizations in the US, as follows: Minnesota (Enernex, WindLogics); New York (GE, AWS/Truewind); Colorado (Enernex, WindLogics); California (NREL, California Wind Energy Collaborative, Oak Ridge National Laboratory, Dynamic Design Engineering, Inc., CAISO); PacifiCorp (PacifiCorp); Texas (GE, AWS/Truewind, ERCOT); Transmission Cost Survey (Lawrence Berkley National Laboratory).

Contents

List of symbols/acronyms

AGC	Automatic Generation Control
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
ELCC	Effective Load Carrying Capability
FACTS	Flexible AC Transmission System
FRT	Fault-Ride-Through
LOEE	Loss of Energy Expectation
LOLE	Loss of Load Expectation
LOLP	Loss of Load Probability
LVRT	Low-voltage ride-through
MAE	Mean Absolute Error, measure for prediction errors
MAPE	Mean Absolute Power Error, error relative to average power, not total installed power, measure for prediction errors
NMAE	Normalised Mean Absolute Error, measure for prediction errors (usually normalised with the installed wind power capacity)
NRMS	Normalised Root-Mean-Square error, measure for prediction errors
RMS	Root-Mean-Square error, measure for prediction errors
SCADA	Supervision Control And Data Acquisition
Statcom	Static Compensator
SVC	Static Var Compensator
TSO	Transmission System Operator
WT	Wind Turbine

Executive summary

Adding wind power will bring about a variable and only partly predictable source of power generation to a power system that has to balance generation and varying demand at all times. High penetration of wind power has impacts that have to be managed through proper wind power plant interconnection, integration of the generation, transmission planning, and system and market operations. This final report of Task 25 first term presents a summary of selected, recently concluded studies of wind integration impacts from participating countries. The case studies summarized are compared, although this is not an easy task due to different methodology and data used, as well as different assumptions on the interconnection capacity available.

There are already several power systems and control areas coping with large amounts of wind power. Several issues that impact on the amount of wind power that can be integrated have been identified. Aggregation benefits of large areas help in reducing the variability and forecast errors of wind power as well as help in pooling more cost effective balancing resources. An alternative to large balancing areas is to allow and promote intra-day and intra-hour trading between different balancing areas in order to obtain low-cost balancing services. System scheduling and operating electricity markets at less than day-ahead time scales help reduce the forecast errors of wind power that affect operating reserves. Transmission is the key to aggregation benefits, electricity markets and larger balancing areas.

For wind penetration levels of 10–20 % of gross demand in power systems, the cost effectiveness of building new electricity storage is still low (excluding hydro power with large reservoirs or pumped hydro). With higher wind penetration levels the extra flexibility that also storages can provide will be beneficial for the power system operation, provided they are economically competitive with other forms of flexibility. It is important to notice, however, that any storage should be operated according to the needs of aggregated system balancing. It is not cost effective to provide dedicated back-up for wind power in large power systems where the variability of all loads and generators are effectively reduced by aggregating, in the same way as it is not effective to have dedicated storage for outages in a certain thermal power plant, or having specific plants following the variation of a certain load.

Integration cost of wind power: Many studies address integration costs. Integration cost is the extra cost of the design and operation of the non-wind part of the power system when wind power is integrated. Integration cost can be divided into different components arising from the increase in the operational balancing cost and grid reinforcement cost. It is important to note whether a market cost has been estimated or the results refer to technical costs for the power system. A "market cost" include transfer of money from one actor to another actor, while "technical costs" implies a cost for the whole system. Most studies so far have concentrated on the costs of integrating wind into the power system while also cost-benefit analysis work is emerging. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels. Integration costs of wind power need to be compared to something, like the production costs or market value of wind power, or integration cost of other production forms. To enable fair comparison between power systems with differing amounts of wind power, these systems should in principle have same CO_2 emissions, reliability, etc. The value of the capacity credit of wind power can also be stated.

Increase in short term reserve requirements due to wind power: Wind generation may require system operators to carry additional operating reserves. From both the experience and results from studies performed, a significant challenge is the variability of wind power within 1–6 hrs. Frequency control (time scale of seconds) and inertial response are not crucial problems when integrating wind power into large systems at the present time, but can be a challenge for small systems and will become more of a challenge for systems with high penetration in the future. The increase in short term reserve requirement is mostly estimated by statistical methods combining the variability or forecast errors of wind power to that of load and investigating the increase in the largest variations seen by the system. The impact of wind power is mostly seen in the 10 minutes to some hours time scale, and only little in the second to second automatic frequency control time scale. The estimated increase in short term reserve requirements in the studies summarised in this report has a large range: 1–15 % of installed wind power capacity at 10 % penetration (of gross demand) and 4–18 % of installed wind power capacity at 20 % penetration. It is of central importance to separate need of flexibility in longer time scales of several hours to a day (power plants that can follow net load variation) and need of reserves that can be activated in seconds or minutes time scale (power plants that can follow *unforecasted* net load variations).

An important issue is that "increase in reserve requirements" does not necessarily mean need of new investments. The amount of wind-caused reserves is at highest when wind power is on a high production level. In these situations the other power stations are operated on a low level, which means that they can act as reserves and increase the generation if wind power decreases. This must be considered when "increased reserve margins" are to be estimated. From the cost estimates presented in investigated studies it follows that at wind penetrations of up to 20 % of gross demand (energy), system operating cost increases arising from wind variability and uncertainty amounted to about 1–4 €/MWh wind power produced. This is 10 % or less of the wholesale value of the wind energy. The actual impact of adding wind generation in different balancing areas can vary depending on local factors. Important factors identified to reduce integration costs are aggregating wind plant output over large geographical regions, larger balancing areas, and operating the power system closer to the delivery hour with accurate forecast systems.

Transmission planning with wind power: With current technology, new wind power plants are able to meet system operator expectations such as riding through voltage dips, supplying reactive power to the system, controlling terminal voltage, and participating in SCADA system operation with output and ramp rate control. Grid reinforcement may be needed for handling larger power flows and maintaining a stable voltage, and is commonly needed if new generation is installed in weak or congested grids far from load centers, or where no grid exists, such as offshore. Transmission cost is the extra cost in the transmission system when wind power is integrated. Either all extra costs are allocated to wind power, or only part of the extra costs are allocated to wind power – grid reinforcements and new transmission lines often benefit also other consumers or producers and can be used for many purposes, such as increase of reliability and/or increased trading. The cost of grid reinforcements due to wind power is therefore very dependent on where the wind power plants are located relative to load and grid infrastructure, and one must expect numbers to vary from country to country. The grid reinforcement costs from studies in this report vary from 0 €/kW to 270 €/kW. The costs are not continuous; there can be single very high cost reinforcements. There are also differences in national studies on how the costs are allocated to wind power – part of the reinforcements are usually made also for other reasons than wind power. It is also important to note that grid reinforcements should be held up against the option of controlling wind output or altering operation of other generation in cases where grid adequacy is insufficient during only part of the time or for only some production and load situations. For transmission planning, the most cost effective solution in cases that demand considerable grid reinforcements would be to plan and expand the transmission network for the final amount of wind power in the system – instead of sequentially planning for multiple phases of incremental expansion.

Capacity value of wind power: Wind generation will also provide some additional load carrying capability to meet forecasted increases in system demand. This contribution can be up to 40 % of installed capacity if wind power production at times of high load is high, and down to 5 % in higher penetrations or if local wind characteristics correlate negatively with the system load profile. Aggregating larger areas benefits the capacity credit of wind power. Regarding estimating the capacity value of wind power, there are several approaches used. Determining the Loss-of-Load-Probability (LOLP) of the power system for different load levels is the most rigorous methodology available. An important issue is whether wind power owners will be paid for the capacity value or not. This is also an issue for other types of power plants and depends on the market regulation. Some reports use the term "capacity cost". The definition of this term is the cost for the compensation for the difference in capacity value for wind power and capacity value for a conventional power plant. This "capacity cost" is not now in widespread use, but it is important to note that when it is calculated this compensation should be added in power plants with very low utilization time, such as open cycle gas turbines (OCGT). An alternative is to use voluntary load reduction. Both these alternatives have comparatively low capacity costs.

Recommendations for wind integration studies: (i) capturing the smoothed out variability of wind power production time series for the geographic diversity assumed and utilizing wind forecasting best practice for the uncertainty of wind power production (ii) examining wind variation in combination with load variations, coupled with actual historic utility load and load forecasts (iii) capturing system characteristics and response through operational simulations and modelling (iv) examining actual costs independent of tariff design structure and (v) comparing the costs and benefits of wind power. In most cases the question is whether extra investments to power systems are economically profitable or not in the new system with larger amount of wind power – not only stating that a certain amount of extra reserve capacity and/or new transmission lines etc are a prerequisite in order to build any wind power.

For high penetration levels of wind power, the optimisation of the integrated system should be explored. Modifications to system configuration and operation practices to accommodate high wind penetration may be required. Not all current system operation techniques are designed to correctly incorporate the characteristics of wind generation and surely were not developed with that objective in mind. Increasing power system flexibility through such means as transmission to neighbouring areas, generation flexibility, demand side management and optimal use of storage (e.g. pumping hydro or thermal) in combination with market aggregation and operation closer to real time will impact the amount of wind that can be integrated cost effectively. There is growing recognition of the need to assess wind power integration at the international level to identify the needs and benefits of interconnection of national power systems in achieving stated policy goals of accommodating higher levels of renewable energy penetration.

Future work: Wind integration has been studied to wind penetration levels of 10–20 % of gross demand (up to 50 % of peak load). What happens in larger penetration levels, where wind becomes a more dominating part of power system, is not completely clear – the future power systems may also provide different options for flexibility in demand side that do not exist today. Furthermore, future integration studies should take into account the foreseen high penetration of PV or ocean power and in similar manner and in many regions this will help smoothing the variability of individual technologies. Generalising the findings to give rough estimates for wind integration efforts and costs for different kind of power systems remains a task for the next phase of Task 25.

1. Introduction

The existing targets for wind power anticipate a quite high penetration of wind power in many countries. It is technically possible to integrate very large amounts of wind capacity in power systems, the limits arising from how much can be integrated at socially and economically acceptable costs. So far 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 in most countries and power systems. However, already some regions (e.g. West Denmark, North of Germany and Galicia in Spain) show a high penetration and have provided the first practical experience from wind integration.

Wind power production introduces additional variability and uncertainty into the operation of the power system. To meet this challenge, there will be need for more flexibility in the power system. How much extra flexibility is required depends on the one hand on how much wind power is embedded in the system, and on the other hand on how much flexibility already exists in the power system.

In recent years, numerous reports have been published in many countries investigating the power system impacts of wind generation. However, the results on the technical constraints and costs of wind integration differ and comparisons are difficult to make due to different methodologies, data and tools used, as well as terminology and metrics in representing the results. Estimating the cost of impacts can be too conservative for example due to lack of sufficient data. Some efforts on compiling the results have been made in (DeMeo et al., 2005; Axelsson et al., 2005; UKERC, 2006). The conclusion has, however, been that due to lack of detailed information on the methodologies used, a direct comparison can only be made with a few results. An in-depth review of the studies is needed to draw conclusions on the range of integration costs for wind power. This requires international collaboration. As system impact studies are often the first steps taken towards defining feasible wind penetration targets within each country or power system control area, it is important that commonly accepted standard methodologies related to these issues are applied.

The circumstances in each country, state or power system are unique with regard to wind integration. However, with careful analysis pointing out the differences, some general remarks can be made, at least when classifying the different case studies with relation to wind penetration and power system characteristics.

In the state-of-the-art report (Holttinen et al., 2007) a first approach to collect and share information on the experience gained and the studies conducted was made, with analyses and guidelines on methodologies. The national case studies address different impacts: balancing the power system on different short term time-scales; grid congestion, reinforcement and stability as well as power adequacy. Further case studies that have been published in 2007–2008 have been added to this Final report. A summary of on-going research is given in Appendix 1.

For the case studies reviewed in this report, the emphasis is on more recent studies and especially on those that have tried to quantify the power system impacts of wind power. The review process will search for reasons behind the wide range of results for costs of wind integration – definitions for wind penetration, reserves and costs; different power system and load characteristics and operational rules; underlying assumptions on variability of wind, generation mix and fuel costs, size of balancing area, etc.

This report starts with a description of wind power variability and predictability as well as introducing power system impacts of wind power in Chapter 2. The case study results and description of methodology are divided in three sections: Chapter 3 for balancing, Chapter 4 for grid and Chapter 5 for power adequacy. The emphasis has been on studies that have tried to quantify the power system impacts of wind power, as well as on the more recent studies. In Chapter 6, experience from high penetration regions so far is summarised, and in Chapter 7 the results from the case studies are summarised. Chapter 8 lists the current best practices in integration studies so far. Chapter 9 contains conclusions and discussion.

2. Power system impacts of wind power

Wind power brings more variability and uncertainty to power systems. This has potential impacts on power system reliability and efficiency. These impacts can in principle be either positive or negative; however, large amounts of wind power usually turn even positive impacts to negative at some stage of penetration level with regards to the cost of integration. This section summarises the results of wind variability and uncertainty and lists the possible power system impacts of wind power.

2.1 Wind power characteristics

For power system operation the following characteristics are relevant: the knowledge of wind power variability and predictability; the knowledge of wind turbine capabilities in providing ancillary services and the knowledge of future wind power installations to help system planning.

2.1.1 Variability of wind power production

It is very important to take the variability of wind into account in a right way in power system studies. The variability will smooth out to some extent if there is geospread wind power, and part of the variability can be forecast. Because of spatial variations of wind from turbine to turbine in a wind power plant – and to a greater degree from wind power plant to wind power plant – a sudden loss of all wind power on a system simultaneously due to a loss of wind is not a credible event. Sudden loss of large amounts of wind power due to voltage dips in the grid can be prevented by requiring fault-ride-through from the turbines.

The variability of wind has been widely studied. Recently also measured large scale wind power production data has become available to give insight on the variability that is relevant for power system operation (Fig 1). In-depth information about the variability can be found in (Ernst, 1999; Focken et al., 2001; Holttinen, 2004; Wan, 2005; EWEA, 2005; IEA 2005; Giebel, 2007).

Generally, the variability of wind decreases as there are more turbines and wind power plants distributed over the area. Larger areas also decrease the number of hours of zero output – one wind power plant can have zero output for more than 1 000 hours during a year, whereas the output of aggregated wind power in a very large area is always above 0. The variability also decreases as the time scale decreases – the second and minute variability of large scale wind power is generally small, whereas the variability over several hours can be large even for distributed wind power. For time scales from several hours to day-ahead, forecasting of wind power production is crucial.

Even if some general conclusions can be drawn from the variability of large-scale wind power, however, it should be noted that the size of the area and the way wind power plants are distributed is crucial. Also the landscape can have influence. Offshore, the wind resource has been found to be more coherent, thus increasing the variability compared to similarly distributed wind power onshore.

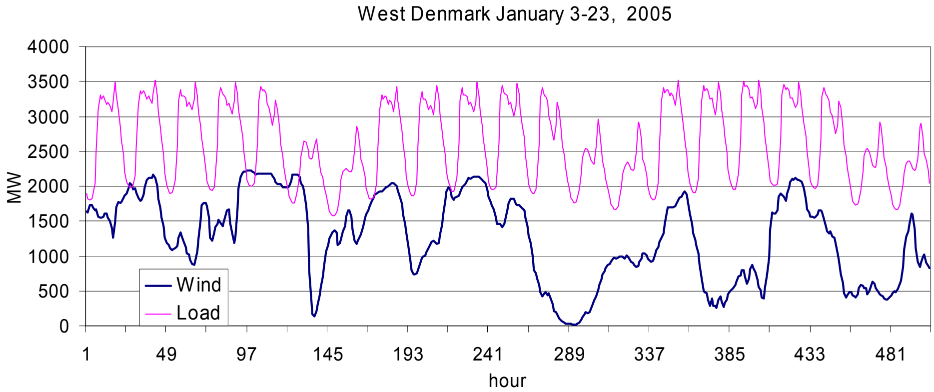


Fig 1. Wind power production (2 400 MW wind power) and load in Western Denmark. The storm event of 8th January can be seen in hours 128–139. (Data source: http://www.energinet.dk.)

General findings on large-scale variability can be summarised as:

- Very fast variations of distributed wind power are low (second-minute level). This is illustrated with data for a single wind power plant in Table 1, where the standard deviation of 1 sec variations is only 0.1 % for a large wind power plant. Smoothing can be seen also in the 1 minute step changes where the standard deviation decreases from 2.1 % to 0.6 % of nominal capacity moving from 14 turbines to 250 turbines. There is increase in variability from the 10 minute to the hourly time scale. The hourly variations do not smooth out very much inside one wind power plant.

- The largest hourly step changes recorded from regional distributed wind power are summarised in Table 2 and range from ± 10 % to ± 35 % depending on region size and how dispersed the wind power plants are. These are extreme values. Most of the time the hourly variations will be within ± 5 % of installed capacity (Fig 3, Fig 4, Fig 5). The German example illustrates this: wind power changes are inside ±1 % of the installed power 84 % of time for 15 minute intervals and 70 % of the time for 1 hour time intervals (Fig 4).

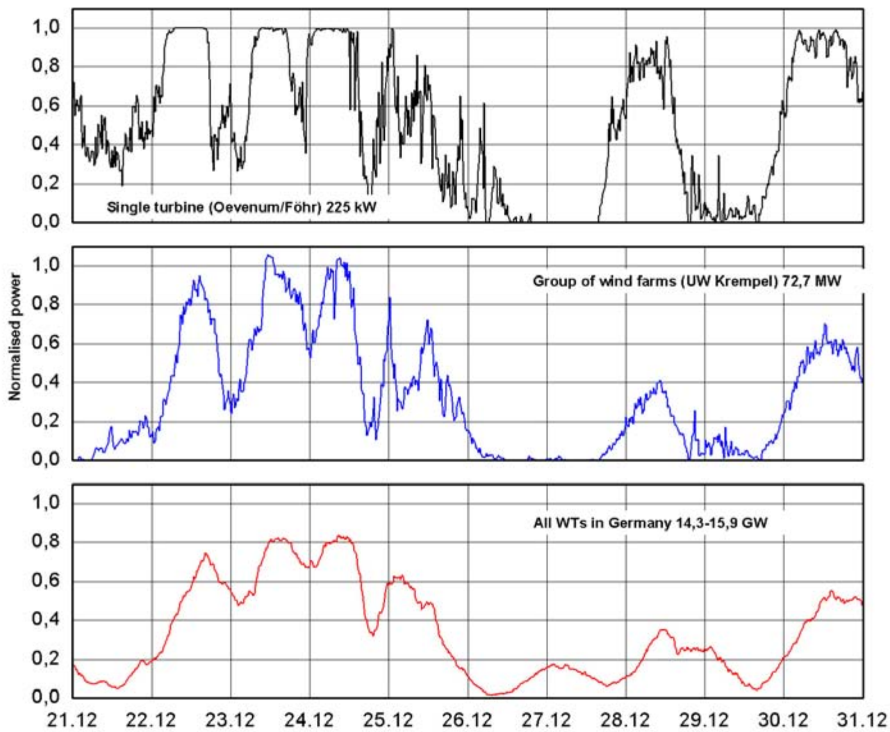


Fig 2. Example of time series of normalised power output from a single WT, a group of Wind power plants and all WTs in Germany (21.–31.12.2004).

- Wind power production can vary a lot in longer time scales, like 4–12 hours. For this time scale, forecasting the production can help. In extreme storm situations turbines stop from full power. Storm fronts take 4–6 hours to pass over an area of several hundreds of kilometres. Extreme ramp rates recorded during storms:
    - Denmark: 2 000 MW (83 % of capacity) decrease in 6 hours or 12 MW (0.5 % of capacity) in a minute on 8th January, 2005 (Eriksen et al., 2005).
    - North Germany: over 4 000 MW (58 % of capacity) decrease within 10 hours, extreme negative ramp rate of 16 MW/min (0.2 % of capacity) on 24th December, 2004 (Fig 2).
    - Ireland: 63 MW in 15 mins (approx 12 % of capacity at the time), 144 MW in 1 hour (approx 29 % of capacity) and 338 MW in 12 hours (approx 68 % of capacity) (from TSO Eirgrid data).
    - Portugal: 700 MW (60 % of capacity) decrease in 8 hours on 1st June, 2006.
    - Spain: Large ramp rates recorded for about 11 GW of wind power: 800 MW (7 %) increase in 45 minutes (ramp rate of 1 067 MW/h, 9 % of capacity), and 1 000 MW (9 %) decrease in 1 hour and 45 minutes (ramp rate -570 MW/h, 5 % of capacity) (from TSO REE). Generated wind power between 25 MW and 8 375 MW have occurred (0.2 %–72 % of capacity).
    - Texas, US: loss of 1 550 MW of wind capacity at the rate of approximately 600 MW/hr over a 2 ½ hour period on February 24, 2007 (ERCOT, 2007).

For large offshore wind power plants ramp rates can be more dramatic and this should be taken into account if most of the wind power capacity in the region is concentrated on one offshore site.

Table 1. Wind power step change average magnitude and standard deviation (Std) values as a function of an increasing number of aggregated wind turbines in a large wind plant in the Midwest of the US (Wan, 2005).

		14 turbines		**61 turbines**		**138 turbines**		**250+ turbines**	
		(kW)	(%)	(kW)	(%)	(kW)	(%)	(kW)	(%)
1-second	Average	41	0.4	172	0.2	148	0.1	189	0.1
1-second	Std	56	0.5	203	0.3	203	0.2	257	0.1
1-minute	Average	130	1.2	612	0.8	494	0.5	730	0.3
1-minute	Std	225	2.1	1 038	1.3	849	0.8	1 486	0.6
10-minute	Average	329	3.1	1 658	2.1	2 243	2.2	3 713	1.5
10-minute	Std	548	5.2	2 750	3.5	3 810	3.7	6 418	2.7
1-hour	Average	736	7.0	3 732	4.7	6 582	6.4	12 755	5.3
1-hour	Std	1 124	10.7	5 932	7.5	10 032	9.7	19 213	7.9

Table 2. Extreme variations of large scale regional wind power, as % of installed capacity. The distribution of variations can be seen in next page Figs. (Denmark, data 2000–2002 from http://www.energinet.dk. Ireland, Eirgrid data, 2004–2005. Germany, ISET, 2005. Finland, years 2005–2007 (Holmgren, 2008). Sweden, simulated data for 56 wind sites 1992–2001 (Axelsson et al., 2005). US, NREL years 2003–2005. Portugal, INETI.

			10–15 minutes		**1 hour**		**4 hours**		**12 hours**	
Region	Region size	Number of sites	max decrease	max increase	max decrease	max increase	max decrease	max increase	max decrease	max increase
Denmark	300x300 km^2	>100			-23%	+20%	-62%	+53%	-74%	+79%
-West Denmark	200x200 km^2	>100			-26%	+20%	-70%	+57%	-74%	+84%
-East Denmark	200x200 km^2	>100			-25%	+36%	-65%	+72%	-74%	+72%
Ireland	280x480 km^2	11	-12%	+12%	-30%	+30%	-50%	+50%	-70%	+70%
Portugal	300x800 km^2	29	-12%	+12%	-16%	+13%	-34%	+23%	-52%	+43%
Germany	400x400 km^2	>100	-6%	+6%	-17%	+12%	-40%	+27%		
Finland	400x900 km^2	30			-16%	+16%	-41%	+40%	-66%	+59%
Sweden	400x900 km^2	56			-17%	+19%	-40%	+40%		
US Midwest	200x200 km^2	3	-34%	+30%	-39%	+35%	-58%	+60%	-78%	+81%
US Texas	490x490 km^2	3	-39%	+39%	-38%	+36%	-59%	+55%	-74%	+76%
US Midwest+OK	1 200x1 200km^2	4	-26%	+27%	-31%	+28%	-48%	+52%	-73%	+75%

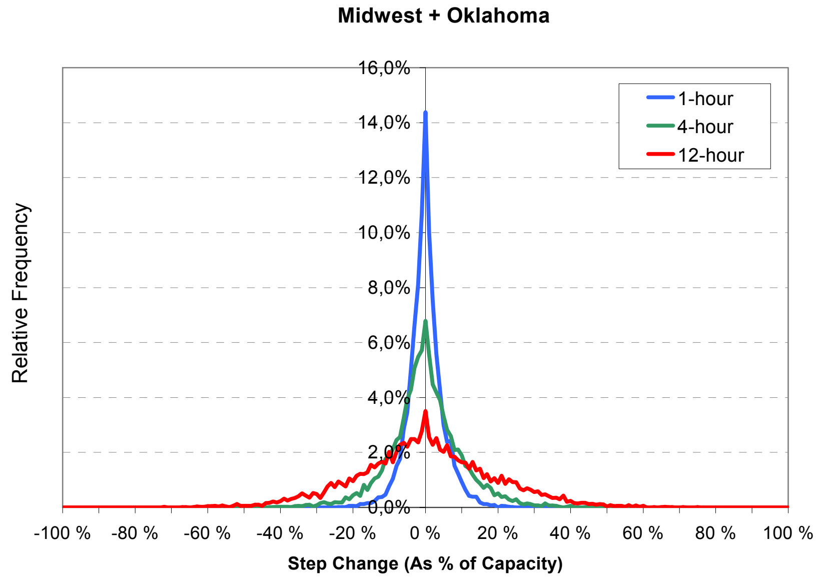


Fig 3. Distribution of hourly, 4-hourly and 12-hourly step changes from aggregation of large wind power plants in the U.S. Midwest and Oklahoma (Wan, 2005).

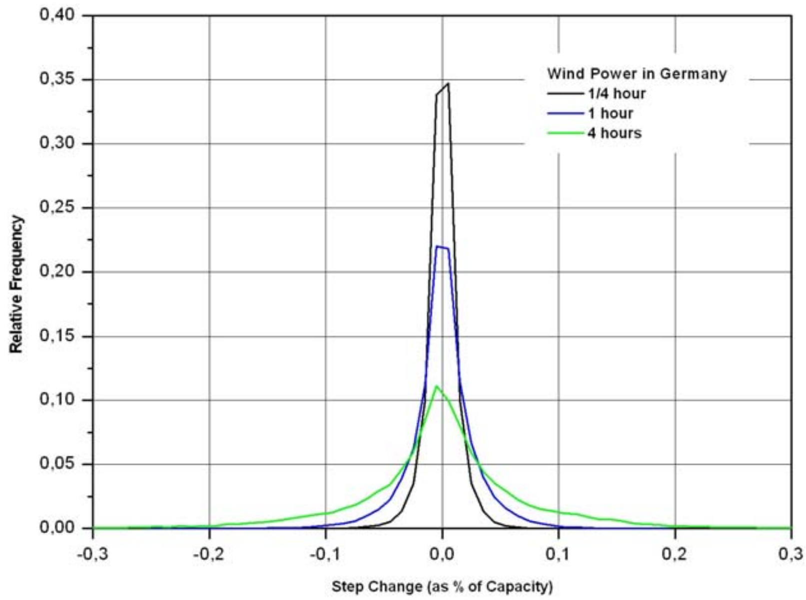


Fig 4. Frequency of relative power changes in ¼, 1 and 4 hour intervals, Germany, 01/01–31/12/2004 (ISET, 2005). A positive value reflects an increase in power and a negative value a decrease.

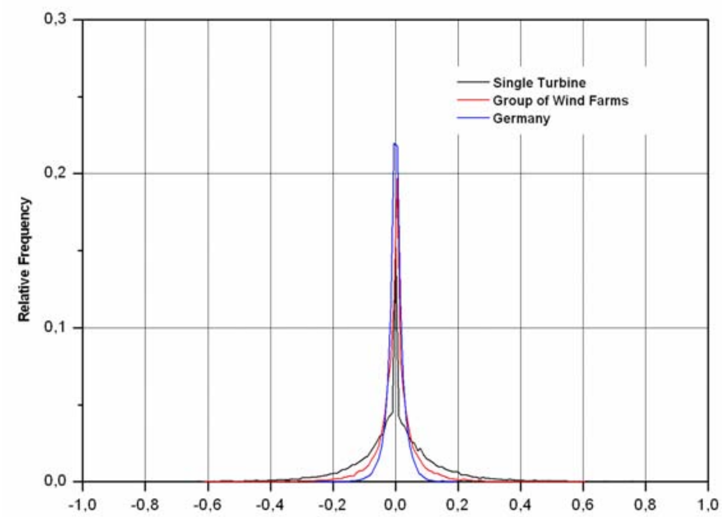


Fig 5. Frequency of relative power changes in 1 hour intervals (15 min mean values) from a single WT, a group of wind power plants and all WTs in Germany, 01/01– 31/12/2004 (ISET, 2005). A positive value reflects an increase in power and a negative value a decrease.

The smoothing effect of wind power production from larger areas is due to low correlation of production from different sites. This is especially pronounced for the variations of production (Fig 6).

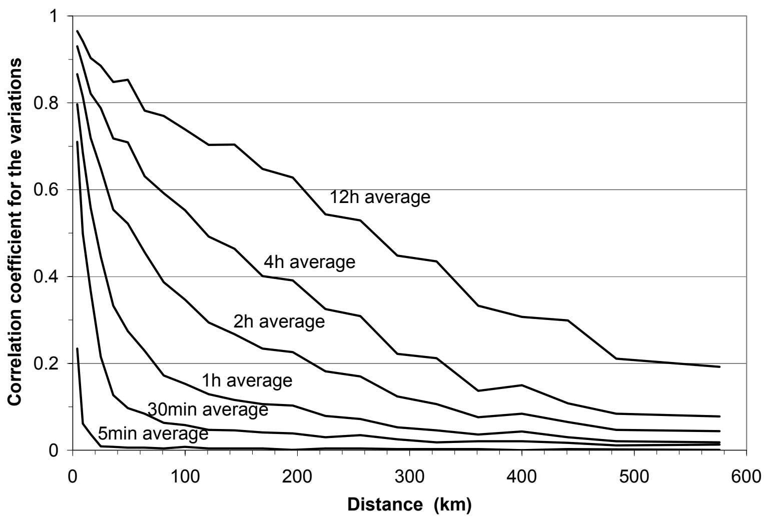


Fig 6. Variations of wind power production will smooth out faster when the time scale is small. Correlation of variations for different time scales, example from Germany (Ernst, 1999).

Wind power variability and the smoothing effect due to geospread wind power plants can be quantified for example by looking at the standard deviation of the time series for variations (Fig 7). There are differences in how the variations smooth out in different regions, as can be seen from Fig 7. Part of the differences can be due to fewer wind power plant sites in the data – the data from US and Ireland, as well as the white dots for Norway and Sweden consist of less than 20 sites. The data from Denmark and Germany represent a well dispersed wind power production. However, in some power systems the wind power plants will not be built as dispersed but in more concentrated large wind power plants. The data from 3 years in Denmark and US suggests that one year gives rather good estimate for the variability – the difference in the stdev values for different years are smaller than the variations in wind resource.

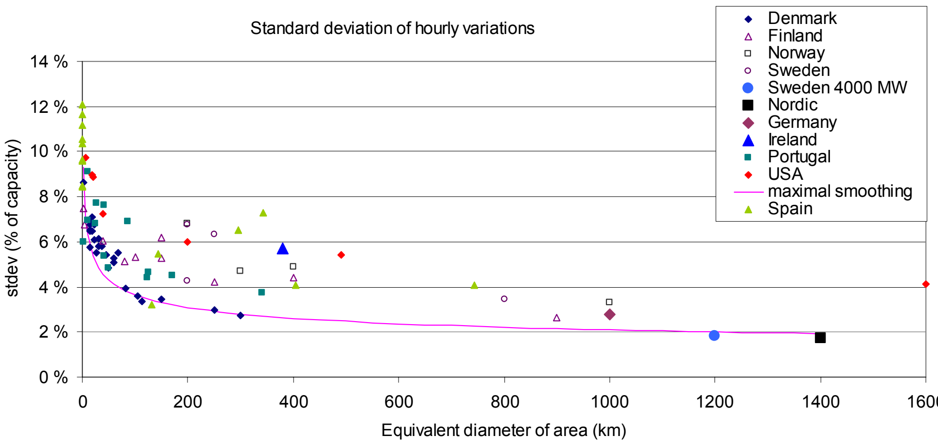


Fig 7. Reduction in variability of wind power production: reduction in standard deviation of hourly variations taken from wind power production data (except Sweden 4 000 MW data from simulations for 56 sites) for different areas (Holttinen, 2004; ISET; Estanqueiro, 2006; Wan, 2005; Axelsson et al., 2005; Ilex et al., 2004; Martin et al., 2009). The line is an estimate for the maximum smoothing effect for the size of the area.

2.1.2 Predictability of wind power production

The short-term forecasting of wind power production is still a recent power system tool when compared to load forecasting. For wind power, the level of accuracy will not be as high as for load. The experience so far shows that the overall shape of the production can be predicted most of the time. However, large deviations can occur both in the level and in the timing of the winds (Giebel et al., 2003; Kariniotakis et al., 2006). For power system operation, the uncertainty of the forecast is as important as the level of accuracy.

Level of accuracy improves when combining predictions for larger areas (Fig 8). For a single wind power plant the mean error for day-ahead forecasts is between 10 % to 20 % (as RMSE % of nominal capacity). For a single control area this error will be below 10 % (Table 3). The latest results from West Denmark day-ahead forecasts show an average prediction error MAE (mean absolute error) of 6.0 % of installed capacity (1), as an RMSE (root-mean-square-error) the error is 8.9 % (2). In these numbers the relative forecast errors are to nominal capacity of wind power. When looking at the relative errors to average power (which give errors in terms of energy) the 6.0 % for West Denmark corresponds to an error of 24 % of yearly energy (3). The forecasts refer to day ahead, i.e. t + 13 … t + 37 hours and are based on a wind power capacity of 1 512 MW.

Further reductions can be expected from combining different forecasting models: The first results from Germany show the best model performing at 5.1 % RMSE, a “simple” combination 4.2 % and “intelligent” combination 3.9 % (Focken, 2007).

$$MAE = \frac{1}{N_h}\sum_{N_h}\frac{|error(h)|}{P_{installed}(h)} = 6.0\% \tag{1}$$

$$RMSE = \frac{1}{N_h}\sum_{N_h}\sqrt{\left(\frac{error(h)}{P_{installed}(h)}\right)^2} = 8.9\% \tag{2}$$

$$MAPE = \frac{\sum_{N_h}|error(h)|}{\sum_{N_h} production(h)} = 23.8\% \tag{3}$$

The level of accuracy also improves when the forecast horizon decreases (Fig 9, Fig 10, Table 3).

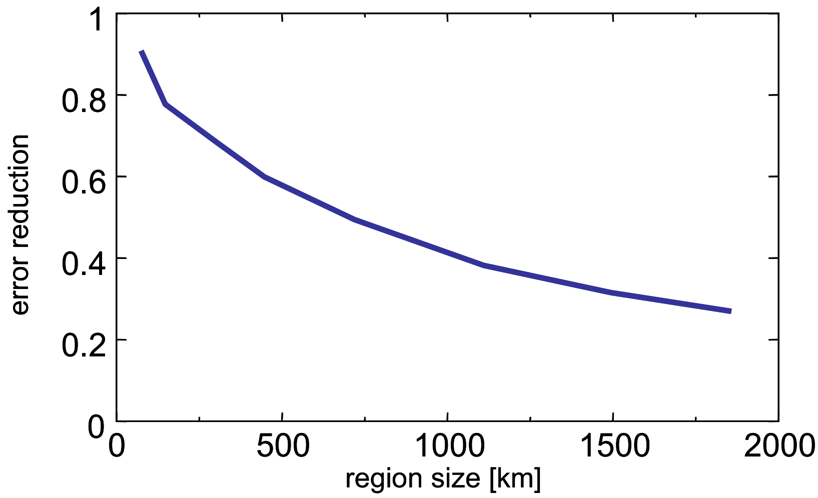


Fig 8. Decrease of forecast error of prediction for aggregated wind power production due to spatial smoothing effects. Error reduction = ratio between rmse (root-mean-square-error) of regional prediction and rmse of single site, based on results of measured power production of 40 wind farms in Germany. Source: Energy & meteo systems.

Table 3. Level of accuracy of wind power predictions will increase when predicting to larger areas and for shorter time scales. Example from Germany (NRMSE = normalized root mean square error, % of installed wind capacity). Source: Rohrig, 2005.

NRMSE [%]	**Germany (all 4 control zones) ~1 000 km**	**1 control zone ~ 350 km**
day-ahead	5.7	6.8
4h ahead	3.6	4.7
2h ahead	2.6	3.5

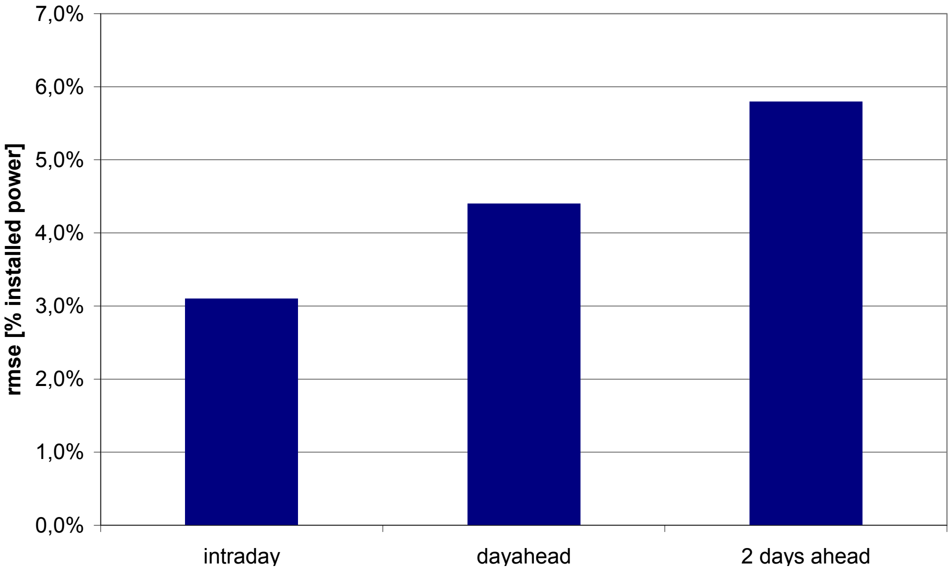


Fig 9. Increasing forecast error as forecast time horizon increases. Results from regional wind power production from Germany (Krauss et al., 2006).

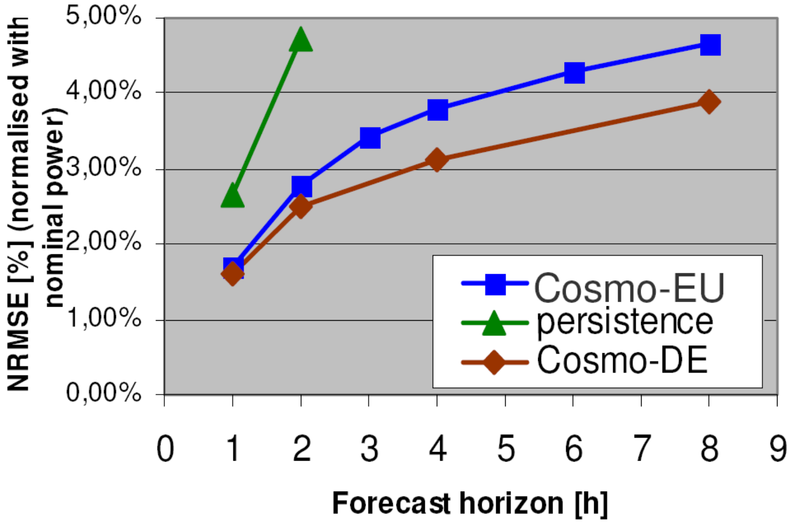


Fig 10. The latest prediction models can improve considerably also the short term production forecasts of wind power. Normalised RMSE error for the wind power production forecast for Germany using two (Cosmo-DE and Cosmo-EU) data as input. Additionally the persistence is shown for the first two hours (Wessel et al., 2008).

While the total balancing energy needed for the integration of wind power stems from the mean forecast error, the need for reserve power is closely connected to the largest forecast errors, i.e. the tail in the probability density function (pdf) of forecast errors. Large wind power forecast errors are mainly caused by errors in the underlying weather prediction. Due to the chaotic nature of the weather, the pdf of the forecast error is not Gaussian. Fig 11 shows as an example the probability density distribution of errors for a day-ahead wind power forecast for Germany; also shown is a fitted Gaussian distribution. It can be seen that large errors occur much more frequently than expected by a Gaussian distribution, causing a need for large reserve power in comparison to the balancing energy.

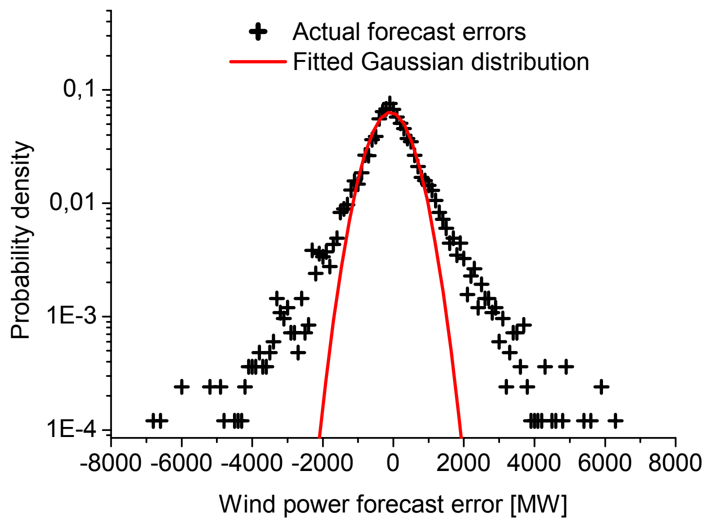


Fig 11. Probability density distribution of errors for the day-ahead wind power forecast for Germany; also shown is a fitted Gaussian distribution. Source: Lange et al., 2006.

2.1.3 Wind turbine capabilities

Wind turbine capabilities are covered in (for example, Cardinal 2006, Gjengedal 2004, Burges et al., 2003). The modern wind turbines are still developing and have possibilities for both tolerance and management of voltage and frequency variations.

Wind power plants can actively take part in grid operation by centrally controlled active and reactive power managed by the wind power plant SCADA.

Active power can be regulated to bear a fixed relationship to the available power, such as maintaining some percentage or some delta value, or set at some fixed value less than the available output. Turbine ramp rate controls can control the rate of increase of active power output, and provide for a smooth plant shutdown. Governor droop characteristics can also be programmed into the power electronic controller, as illustrated in Fig 12. Turbine reactive power controls can be used to regulate either the voltage or power factor to a user defined reference.

Based on the results of several studies and on the experience with existing wind projects, modification of the existing Grid Codes for connection and operation of wind power plants in the high voltage grid have proved necessary, for instance in view of fault-ride-through and grid voltage maintenance. Countries planning very high wind penetration in the near future (e.g. Germany, Portugal and Spain) are already requiring these capacities for new wind park projects. The implementation of the new measures will improve and stabilize wind turbines behaviour and will result in decreasing loss of wind power following disturbances (Erlich et al., 2006; Gómez-Lazaro et al., 2006; Gómez-Lazaro et al., 2007a).

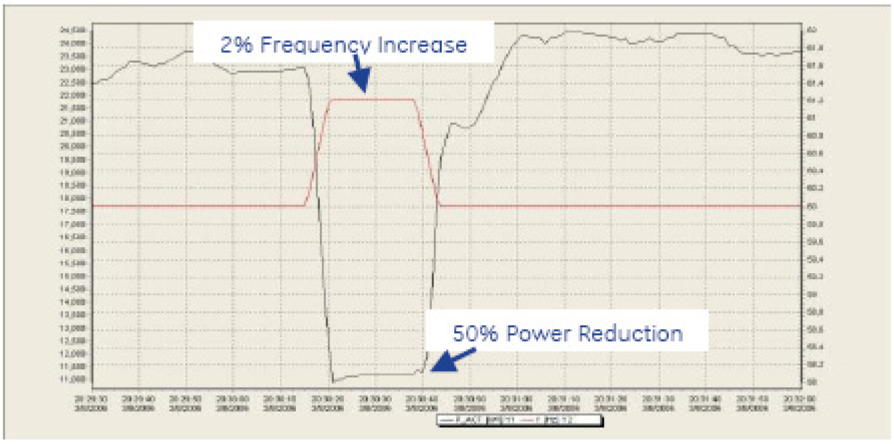


Fig 12. Power response of wind power plant to overfrequency condition (Cardinal & Miller, 2006).

One example of requirements imposed on wind power plants connected to the grid at the transmission system level is the Danish technical requirement (Energinet, 2004) specified by the Danish TSO, Energinet.dk, and implemented e.g. at the Horns Rev offshore wind power plant. The technical requirements specify six types of active power regulation available to the TSO:

- absolute limit of the output of the wind power plant to a specific value set by the operator
- balance regulation where the wind power plant is ordered to reduce the output with a certain amount
- delta control where the output of the wind power plant with a delta amount so this amount can be used as spinning reserve
- rate limitation where the output of the wind power plant is not allowed to increase more than a specified amount per minute
- droop control
- system protection by output reduction.

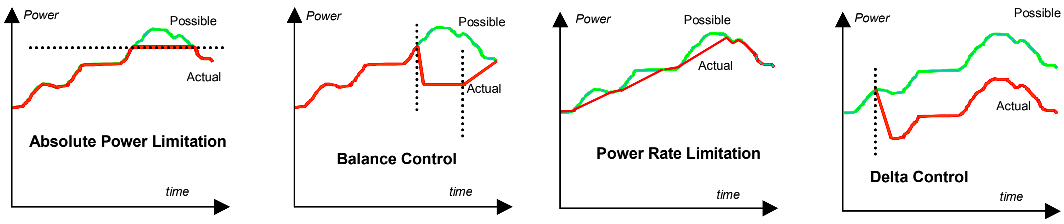


Fig 13. Outline of the active power control functions. The plots show the possible power and the actual achieved power with the different control functions active.

The four first types of regulation are illustrated in Fig 13. Results from the Horns Rev wind power plant executing several types of regulation commanded are shown in Fig 14 (Kristoffersen, 2005). It shows that the wind power plant is quite capable of performing fast regulation of the output.

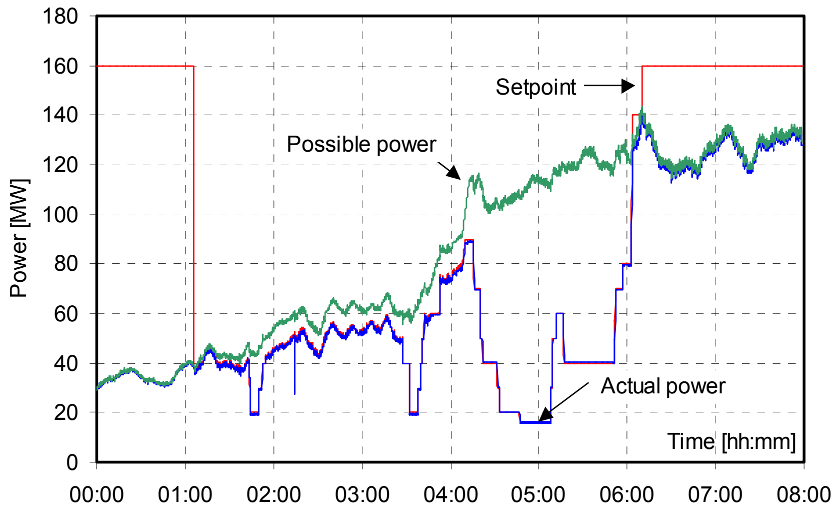


Fig 14. Measured output of Horns Rev wind power plant operating with balance control and reservation for frequency control at the same time (Kristoffersen, 2005).

Other solutions for improving stability of already existing wind power plants are SVC (Static VAr compensator) or STATCOM (Static synchronous compensator) at wind power plants.

The possibilities for providing support for power system control come at a cost of either increased investment cost or production losses. This makes the issue more complex and it is mainly being considered at very high wind penetrations (e.g. above 15 %) and isolated and/or weak grids.

2.1.4 Grid code requirements for wind power plants

Grid codes determine what is required of power plants when connecting to the network. The new grid code requirements for wind power plants in many countries include a requirement for low-voltage ride-through (LVRT, also called FRT fault-ride-through) in the event of system faults. The generator must stay online during three phase and single line to ground faults and in a range of grid frequencies. The fault clearing times as well as the voltage dip requirements and the requirements for providing voltage support during the fault, vary in the codes implemented so far (Fig 15). The grid code can also include a requirement for reactive power control (e.g. of 0.95 at the point of interconnection), and the need to supply SCADA data as agreed with the TSO. Additional requirements that are being met when requested include voltage control, active power and frequency control (e.g. ramp rate control). Verified plant models can also be required to be supplied for simulation purposes (Smith et al., 2007).

The grid code requirements are being met by commercial wind plants entering service today, either through the inherent capability of the wind turbine technology being deployed or through the addition of suitable terminal equipment, such as some combination of static and dynamic shunt compensation.

Increased demands will be placed on wind plant performance in the future. Future requirements are likely to include post-fault machine-response characteristics more similar to those of conventional generators (e.g. inertial response and governor response).

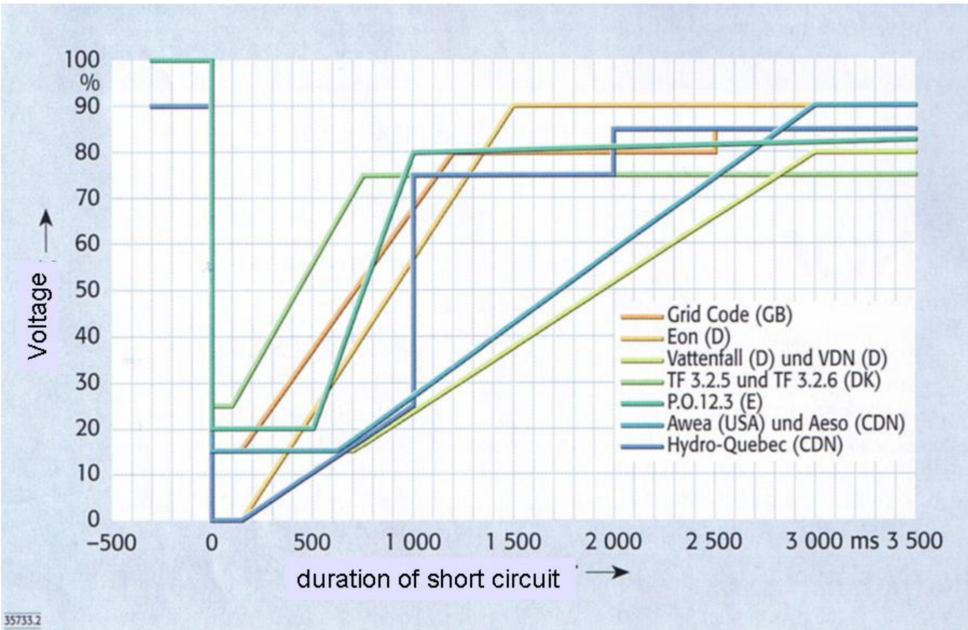


Fig 15. Comparison of fault ride through requirements. Source: Elektrizitätszwirtschaft, 2006.

2.1.5 Foreseeing the building of wind power capacity

Wind power has a short construction lead time compared with building transmission. In most cases there is not enough information available on the future wind power sites in time for power system planning purposes. The national and global trends and reasons behind the capacity increase of wind power are the need for emission free electricity, especially decreasing greenhouse gas emissions, as well as efforts to reduce fossil fuel dependence due to scarcity and price volatility (covered in e.g. GWEC, 2005; Bird et al., 2003). The way in which these needs are implemented in policy frameworks for renewable energy strongly determines the local (national) growth rate of the installed wind power capacity (e.g. Germany, Spain).

In many cases wind capacity development is depending on network extension or reinforcement. As network planning / permitting / implementation starts only if the project is able to apply formally (permits acquired, financing assured) this can create a barrier for smooth implementation.

Wind resource studies are needed in order to get knowledge on the geographic areas where the resource exists and the total MW possible to be implemented, also depending on the environmental sensitivity of the areas. The study results can also be used to assess some basic statistical characteristics of the wind in each of these areas and between these areas (see section 2.1.1) (e.g. INEGI, 2002).

2.2 Possible power system impacts of wind power

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. Wind power has impacts on power system reliability and efficiency (Fig 16). These impacts can be either positive or negative.

Different time scales usually mean different models (and data) must be used in impact assessment studies. The case studies for the system wide impacts can thus fall into the following focus areas:

Regulation and load following: (time-scale seconds…half an hour). This is about how the variability and uncertainty introduced by wind power will affect the allocation and use of reserves in the system. Prediction errors of large area wind power should be combined with any other prediction errors the power system experiences, like prediction errors in load. General conclusions on the increase in balancing requirements will depend on region size relevant for balancing, initial load variations and how concentrated or well distributed wind power is sited, as well as the type of terrain orography and local wind structure and typical behaviour. The costs will depend on the marginal costs for providing balancing services or mitigation methods used in the power system for dealing with increased variability and uncertainty. Market rules will also have an impact, as technical costs can be different from market costs.

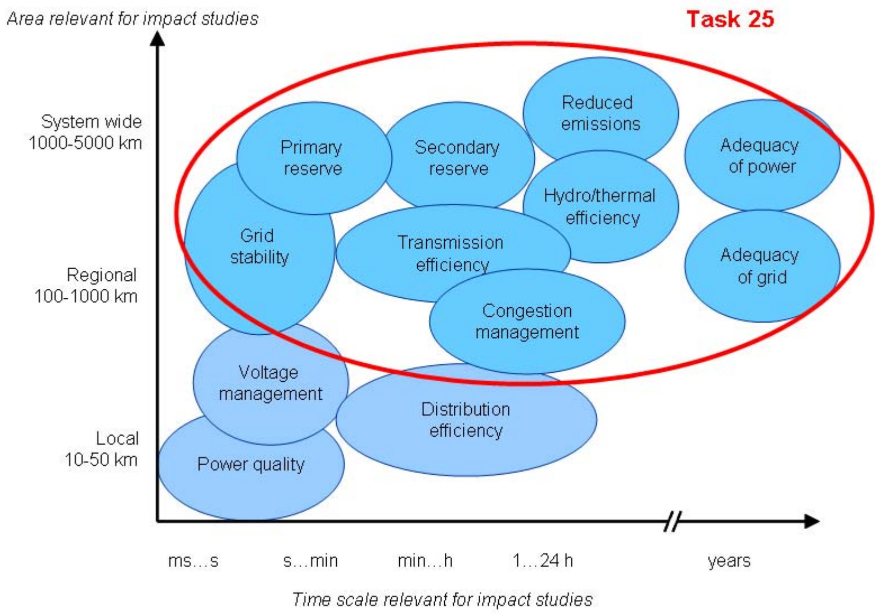


Fig 16. Impacts of wind power on power systems, divided in different time scales and width of area relevant for the studies. In this report (Task 25), more system related issues are addressed, as opposed to local issues of grid connection like power quality. Primary reserve is here denoted for reserves activated in seconds (frequency activated reserve; regulation) and Secondary reserve for reserves activated in 5–15 minutes (minute reserve; load following reserve).

Efficiency and unit commitment: This impact is due to production variability and prediction errors of wind power (time scale: hours to days). Here the interest is on how the conventional capacity is run and how the variations and prediction errors of wind power change the unit commitment: both the time of operation and the way the units are operated (ramp rates, partial operation, starts/stops). Analysing and developing methods of incorporating wind power into existing planning tools is important, to take into account wind power uncertainties and existing flexibilities in the system correctly. The simulation results give insight into the technical impacts of wind power, and also the (technical) costs involved. In electricity markets, prediction errors of wind energy can result in high imbalance costs. Analyses on how current market mechanisms affect wind power producers are also important.

Adequacy of power generation: This is about total supply available during peak load situations (time scale: several years). System adequacy is associated with static conditions of the system. The estimation of the required generation capacity needs includes the system load demand and the maintenance needs of production units (reliability data). 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 issue is the proper assessment of wind power's aggregate capacity credit in the relevant peak load situations – taking into account the effect of geographical dispersion and interconnection. Local storage systems with high energy capacity are also starting to be used in some power systems and may have a strong impact of adequacy of power, when cost competitive.

Transmission adequacy and efficiency: (Time scale: hours to years.) The impacts of wind power on transmission depend on the location of wind power plants relative to the load, and the correlation between wind power production and load consumption. Wind power affects the power flow in the network. It may change the power flow direction, reduce or increase power losses and bottleneck situations. There are a variety of means to maximise the use of existing transmission lines like use of online information (temperature, loads), FACTS and wind power plant output control. However, grid reinforcement may be necessary to maintain transmission adequacy. When determining the reinforcement needs of the grid, both steady-state load flow and dynamic system stability analysis are needed.

System stability: (Time scale: seconds to minutes) Different wind turbine types have different control characteristics and consequently also different possibilities to support the system in normal and system fault situations. More specifically this is related to voltage and power control and to fault ride through capability. The siting of wind power plants relative to load centres will have some influence on this issue as well. For system stability reasons, operation and control properties similar to central power plants are required for wind plants at some stage depending on penetration and power system robustness. System stability studies with different wind turbine technologies are needed in order to test and develop advanced control strategies and possible use of new components (e.g. FACTS) at wind plants or nearby busbars.

2.3 Wind penetration levels in the case studies

The power systems studied in following chapters are summarised in Table 4. Determining what is “high” penetration of wind power is not straightforward. Often either energy or capacity metrics are used: wind power production as % of gross demand (energy) and wind power as % of peak load (capacity). To determine high penetration for a power system also interconnecting capacity needs to be looked at. This is because critical moments of high wind and low load can be relieved by using interconnector capacity. This is why also wind power installed capacity as % of min load + interconnector capacity has been calculated in Table 4.

Table 4. Power system size and wind power penetration studied in national cases.

	Load			**Inter-connect. capacity**	**Wind power**					
					2008	Highest studied		Highest penetration level		
Region / case study	Peak MW	Min MW	TWh/a	MW	MW	MW	TWh/a	% of peak load	% of gross demand	% of (min load + interconn)
West Denmark 2008	3 700	1 300	21	2 830*	2 380	2 380	5	64 %	24 %	58 %
Denmark 2025 a)	7 200	2 600	38	5 190*	3 150	6 500	20.2	90 %	53 %	83 %
Denmark 2025 b)	7 200	2 600	38	6 790*	3 180	6 500	20.2	90 %	53 %	69 %
Nordic /VTT	67 000	24 000	385	3 000*	4 772	18 000	46	27 %	12 %	67 %
Nordic+Germany/ Greennet	155 500	65 600	977	6 600*	28 675	57 500	115	37 %	12 %	80 %
Finland/VTT	14 000	5 900	90	2 280*	143	7 300	16	52 %	18 %	89 %
Germany 2015/Dena	77 955	41 000	552.3	10 000*	23 903	36 000	77.2	46 %	14 %	71 %
Ireland/ESBNG	6 500	2 500	38.5	0	1 002	3 500	10.5	54 %	27 %	140 %
Ireland / SEI	6 900	2 455	39.7	900*	1 002	1 950	5.1	28 %	13 %	58 %
Ireland 2020/All island	9 600	3 500	54	1 000	1 002	6 000	19	63 %	35 %	178 %
Netherlands	25 200	9 000	127	7 350	2 225	10 000	35	40 %	28 %	61 %
Mid Norway/Sintef	3 780		21			1 062	3.2	28 %	15 %	
Portugal	8 800	4 560	49.2	1 000	2 862	5 100	12.8	58 %	26 %	92 %
Spain 2011	53 400	21 500	246.2	2 400	16 754	17 500	46	33 %	19 %	73 %
Sweden	26 000	13 000	140	9 730*	1 021	8 000	20	31 %	14 %	35 %
UK	76 000	24 000	427	2 000*	3 241	38 000	115	50 %	27 %	146 %
US Minnesota 2004	9 933	3 400	48.1	1 500*	1 752	1 500	5.8	15 %	12 %	31 %
US Minnesota 2006	20 000	8 800	85		1 752	6 000	21	30 %	25 %	68 %
US New York	33 000	12 000	170	7 000*	882	3 300	9.9	10 %	6 %	17 %
US Colorado	7 000		36.3		1 068	1 400	3.6	20 %	10 %	
US California	64 300	25 000	304		2 517	12 500	34	19 %	11 %	
US Texas	65 200	16 000	317		7 116	15 000	54	23 %	17 %	

** The use of interconnection capacity to countries outside the modelled area is not taken into account in these studies. In Nordic 2004 study the interconnection capacity between the Nordic countries is taken into account. In Nordic+Germany/Greennet study the 5 modelled countries are divided into 12 regions interconnected by transmission lines, thereby including the influence of interconnection capacity between countries within the modelled area.*

3. Balancing and efficiency of production

Wind power impacts on power system balancing can be seen in several time scales, from minutes to hours, up to the day-ahead time scale. General conclusions on increase in balancing requirement will depend on region size relevant for balancing, initial load variations and how concentrated/distributed wind power is sited. Here also the operational routines of the power system are relevant – how often the forecasts of load and wind are updated, for example. If a re-dispatch based on forecast update is done in 4–6 hours, this would lower the costs of integrating wind compared with scheduling based on only day-ahead forecasts. Emerging intra-day markets reflect this, giving the opportunity for hourly updates. The costs will depend on the marginal costs for providing regulation or mitigation methods used in the power system as well as on the market rules. The way the power system is operated regarding the time lapse between forecast schedules and delivery will impact the degree of uncertainty wind power will bring about.

For efficiency of production, the interest is on how the conventional capacity is run and how the variations and prediction errors of wind power change the unit commitment: both the time of operation and the way the units are operated (ramp rates, partial operation, starts/stops). Developing methods of incorporating wind power uncertainties into existing planning tools and models is important. The simulation results give insight into the technical impacts that wind power has, and also the (technical) costs involved. Analyses on how current market mechanisms affect wind power producers is also important.

3.1 Approaches to assessing balancing requirements and efficiency of production

Effects of wind power on power system operation are in most cases analysed by making simulations of system operation. Reserve requirements, on a time scale of minutes, are often estimated based on statistical methods. In simulation models the reserve requirement can also be calculated based on a statistical approach, and then this reserve requirement can be allocated to generation in the simulation.

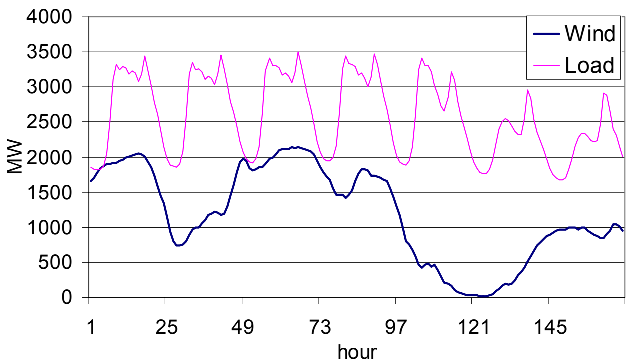
The statistical approach for estimating the increase in reserve requirements is based on looking at the variability as a probability density. Combining the variability of wind with load variations, and looking at the increase in the net load variations is often referred to as the "3σ method" (Milligan, 2003). This means that 3 times the standard deviation can be taken as a confidence level for how much of the variations should be covered by reserves (values of 2–7 have been used instead of 3; Holttinen et al., 2008). Also forced outages can be included when estimating the increase in reserve requirements, which means combining the uncertainty of load, wind and other production. Because of spatial variations of wind from turbine to turbine in a wind plant – and to a greater degree from plant to plant – a sudden loss of all wind power on a system simultaneously due to a loss of wind is not a credible event. This is an important consideration for first contingency evaluation (disturbance/contingency reserves).

In energy system simulations, wind is added to the system and any effects are analysed comparing the production and costs of the system with and without wind. For assessing the cost of variability of wind, the comparison can be made by adding wind as a flat production block over 24 hours, or with a foreseeable diurnal pattern.

3.2 Terminology for reserves

The terminology for reserves varies in every country. In Table 1 of Appendix 3, the terminology in several European countries is presented according to division of the time scales of operating the reserves (Söder et al., 2006). In this report, the reserves are referred to according to these time scales: below 5–10 minutes; 10–15 minutes and more than 15 minutes. In the US the terms regulation, load following and unit commitment are generally used to describe the operation time periods in the studies. When necessary, the division between disturbance (contingency) reserves and operating reserves will be made.

In a power system there are continuous production and consumption changes so the balance between production and consumption has to be kept by use of actively controlled changed production as an answer to the deviation. This means that the following capacity has to be available: $P_k n(t)$ = available units that can increase their production from hour k within time t as much as the net load (= load – wind power + outages) will increase (= the *variability*) during time t. $P_k n(t)$ is here denoted *available flexibility*. Fig 17 shows an example of how the net load can vary during a week, which corresponds to a need of flexibility (the graph has not outages in the net load). A part of net load variation can be forecasted corresponding to possibility to prescheduling of power plants, while one part can not be forecasted which corresponds to a need of reserve capacity, see Fig 18.



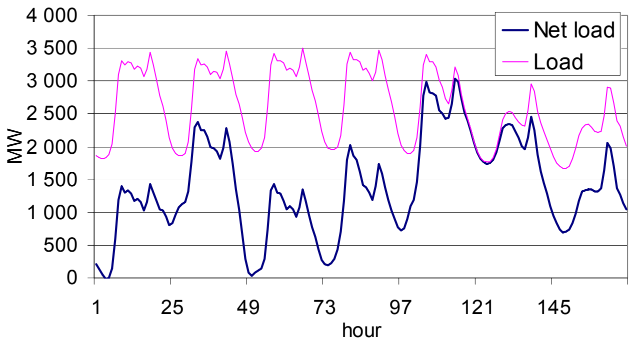


Fig 17. One week of hourly data from West Denmark (10.–16.1.2005), showing the variability of load and wind (upper graph) and resulting net load: Net load = Load – Wind Power = required flexibility in available non-wind power plants. (Source of data: http://www.energinet.dk)

To illustrate the need of flexibility, Fig 18 shows $P_0n(1)$, i.e., needed power increase in 1 hour and $P_0n(3)$, expected power increase needed in three hours time.

- The need of flexibility is not the same as need of reserves, since a part of the net load variation can be forecasted. $P_kf(t)$ = *net load forecast* for time k+t performed at hour k. Fig 18 shows $P_0f(2)$ = the 2 hour forecast performed at hour 0, $P_0f(4)$ = the 4 hour forecast performed at hour 0 and $P_3f(0.5)$ = 0.5 hour forecast performed at hour 3.

- $P_kr(t)$ = available units that can increase their production from hour k within time t as much as the [real net load] – [net load forecast] = $P_kn(t)$ - $P_kf(t)$ (= the *forecast error*) will increase during time t. $P_kr(t)$ is here denoted *reserve capacity*. Fig 18 shows $P_0r(2)$ = needed reserve capacity that could increase its production in 2 hours from hour 0 without being prescheduled and $P_0r(4)$ = needed reserve capacity that could increase its production in 4 hours from hour 0 without being prescheduled. Forecasts can continuously be updated and this is shown in the figure. This means that the new forecast error is decreased and the corresponding half hour needed reserve capacity becomes $P_3r(0,5)$ corresponding to how much capacity that has to be available within 0.5 hours without being prescheduled.

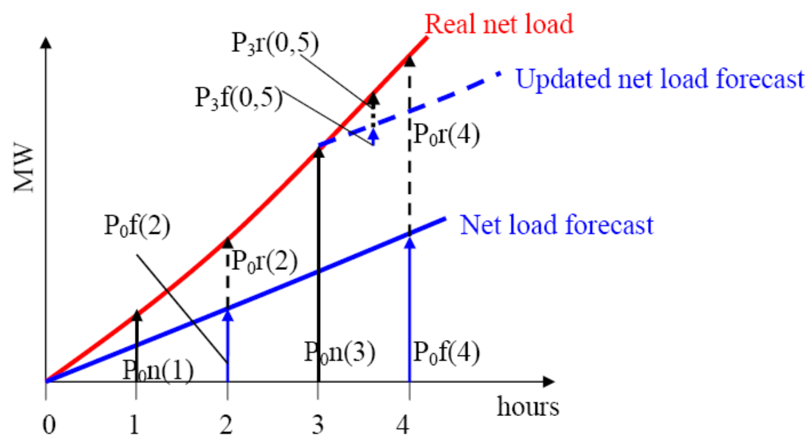


Fig 18. Need of "Flexibility" is the need for some units to follow the "net load variability", marked $P_kn(t)$. This can be partly done by units scheduled beforehand, to follow the "net load forecast", marked $P_kf(t)$, while "reserves" is the need for some units to follow the "net load forecast errors", marked $P_kr(t)$.

The difference between flexibility $P_k n(t)$ and reserves $P_k r(t)$ is that $P_k n(t)$ sets the total flexible capacity that has to be available, while $P_k r(t)$ only includes the part of the flexible capacity that must be available within the time t without being prescheduled. Prescheduling means that power plants with longer start-up times are included in flexibility $P_k n(t)$, because it is assumed that their start-up process is initiated before the actual operation hour such that they are online in time period k+t. The capability of both $P_k n(t)$ and $P_k r(t)$ are strongly connected to the ramp rates of available power plants and in the case of $P_k n(t)$ start-up times of available power plants. The examples in Fig 18 are mainly on hourly bases, but common reserve categories are e.g. “primary reserves” = $P_k r$(around one minute) and “secondary reserves” = $P_k r$(around 10 minutes).

The examples in Fig 18 show a case where production needs to be increased to follow the net load. There is also a need to decrease production when net load decreases. It is generally easier to decrease generation than to increase it, e.g. by disconnection of generating plants (including wind power).

It can be noted that:

- Wind power can only decrease when there is a production level and only decrease largely when there is a large production. In a situation with no wind power, there is no need to include wind power when determining downward reserves or flexibility in the power system.
- In a situation with high wind power production, i.e., a situation with possible decrease of wind power production, other units are not in operation (since some of the load is met with wind power). This means that these units can increase their production if wind power decreases and/or load increases. This is based on the assumption that $P_k 1(t)$ and $P_k 2(t)$ can increase their production fast enough. This means that **flexibility** and **reserve keeping** in a system with wind power is often more **an issue of ramp rates and start-up times**, than a need of more capacity – more fast ramping and starting capacity can be needed, if the forecast errors are large enough that the slow units cannot follow.
- In many real systems (here called system A), there are connections to neighboring systems, (system B). In system A a common approach is then to use a probabilistic (= statistical) approach concerning the need of reserves and flexibility, assuming that during a certain percent of the

time the needed flexibility/reserves are imported from system B. But then the needed reserves in system A also have to consider possible outages in the transmission to system B. This means that one can estimate $P_k1(t)$ and $P_k2(t)$ from a probabilistic density function of possible changes (i.e. *variability* for P_k1) or *forecast error* (for P_k2) and a certain percentage of accepted need for import of power. This method can also be used when one wants to make a rough estimate of needed $P_k1(t)$ or $P_k2(t)$ for a future system based on knowledge of $P_k1(t)$ and $P_k2(t)$ in the current system. Also in systems without interconnections there are some dimensioning criteria which means that one only keep margins for "possible" situations. The term "possible" then normally includes a certain percentage of what in reality could happen. Also in these systems it is possible to use a probabilistic approach. A straightforward method to define "possible" is the commonly used "N-1 criterion", i.e., it is necessary to keep reserves for an outage in the largest unit.

- The different time frames for both $P_k1(t)$ and $P_k2(t)$ are strongly interconnected. If one, e.g., have enough P_k1(4 hours), then this in general *includes* that during this period there must be enough P_k1(1 hour). This means, in this case, that there is no meaning in calculating P_k1(4 hours) + P_k1(1 hour) since they overlap significantly. Such additions are only valid when they contain different units. In reality there is also an overlap between $P_k1(t)$ and $P_k2(t)$. Assume, e.g., that $P_k1(t)$ is available, but the forecasted net load only increases $P_k(t)$ (where $P_k(t)< P_k1(t)$). This means that $P_k1(t)- P_k(t)$ is available to be included in $P_k2(t)$. This is based on that this volume has a ramp rate which is high enough so it does not have to be prescheduled. It can also be noted that if the most extreme increase of net load that have ever happened is $P3(t)$, then this means that in this situation the highest requirement of *available flexibility* will be that $P_k1(t)=P3(t)$. It is then important to note that this includes $P_k2(t)$ so there is **not** a need for the system to cover both $P_k1(t)=P3(t)$ **and** a maximum $P_k2(t)$ to meet uncertainties **at the same time**.
- There is an interaction between "reserves" and market arrangements. If the net load forecasts are relatively accurate for a certain time frame

(e.g. 24 hours) then only a 24 hour market is needed. If, on the other hand, the 24 hour forecasts have low quality, then there has to be a market for changed production within that period. It is not the *variability* that requires updated markets but more the *net load forecast errors*. It must also be noted that, e.g., “24 hour reserves” is not a physical but mainly a market need. Most power plants need maximum 4–6 hours to start up so they do not need this information 24 hour in advance.

3.3 Check-list for review

A list of relevant issues to be taken into account when assessing the impacts of wind power on the power system is presented here. The important issues are:

- **What is the main set-up** for the assessment or simulation: is wind power replacing other production or capacity and to what extent is the power system operation optimised when wind power production is added. What is the level of detail of the simulation model, time resolution, pricing?
- **What is the wind input used** – how well does the wind data represent the geospread of the power system, how is wind power simulated, what time scale effects on variability and predictability have been taken into account.
- How is the **uncertainty in the wind plant output forecast** handled with respect to the load forecast uncertainty. Are both recognized? Are they combined in the proper statistical fashion?
- What is the level of detail in the simulation of conventional generation and transmission? What has been taken into account when modelling **thermal and hydro units and transmission possibilities**.

The matrix developed in (Söder & Holttinen, 2008) has been further processed to form a check-list for the national studies that have used simulations (Table 5). The main idea is to present tables from simulations regarding balancing requirements. When going through this check-list, the idea is to find out whether the approach has been conservative or whether some important aspects have been omitted, producing either high or low estimates for the impacts.

Table 5. Modelling the integration costs of wind power. Methodology and input data to be considered.

<table>
<tr><td colspan="7">Study conducted by + year when made:</td></tr>
<tr><td colspan="7">Geographic area of study + year(s) studied:</td></tr>
<tr><td colspan="7">Power system characteristics:</td></tr>
<tr><td colspan="3">Load</td><td>Installed (non-wind) generation</td><td>Interconnection</td><td colspan="2">Wind power</td></tr>
<tr><td>Peak (MW)</td><td>Min (MW)</td><td>TWh/a</td><td>Capacity (MW)</td><td>Capacity (MW)</td><td>MW</td><td>TWh/a</td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="7">Power system details: thermal-hydro-mixed (MW hydro MW thermal: MW gas MW coal MW nuclear)</td></tr>
<tr><td colspan="7">Interconnection details: MW DC MW AC links, how flexible or bulk contracted the interconnection is, assumptions on how much of this available for regulation/reserves</td></tr>
<tr><td colspan="7">Wind power details: geographical distribution: how wide and how well distributed, offshore-onshore MW amounts; how much transmission / distribution network connected</td></tr>
<tr><td colspan="7">Characteristics of system planning:</td></tr>
<tr><td colspan="7">Description of market:</td></tr>
<tr><td colspan="7">Integration time frames of importance:</td></tr>
<tr><td colspan="7">Set up</td></tr>
<tr><td>A</td><td>Aim of study</td><td colspan="5">1 what happens with x GWh (or y GW) wind
2 how much wind is possible
3 other:</td></tr>
<tr><td>M</td><td>Method to perform study</td><td colspan="5">1 add wind energy
2 wind also replaces capacity
3 load is increased same amount of GWh as wind
4 optimal system design
5 other:
For capacity credit also: a – chronological, using wind power and load profiles b– probabilistic</td></tr>
<tr><td>S</td><td>Simulation model of operation</td><td colspan="5">1 deterministic simulation, one case
2 deterministic simulation several cases
3 deterministic planning with stochastic wind forecast errors
4 Stochastic simulation several cases
5 other:</td></tr>
<tr><td colspan="7">Simulation detail</td></tr>
<tr><td>R</td><td>Resolution of time</td><td colspan="5">1 day/week
2 hour
3 minute/second
DURATION of simulation period:</td></tr>
<tr><td>P</td><td>Pricing method</td><td colspan="5">1 costs of fuels etc.
2 prices for trading with neighbours, historical market prices
3 perfect market simulation (each actor maximizes its benefit according to some definition considering the physical and legal constraints)</td></tr>
</table>

		4 market dynamics included (different actors on the market make investments or change their behaviour depending on the market prices) 5 other:
D	**Design of remaining system**	1 constant remaining system 2 optimized remaining production capacity 3 optimized remaining transmission 4 changed operation due to wind power 5 perfect trading rules 6 other:
Uncertainty and balancing		
I	**Imbalance calculation**	1 only wind cause imbalances 2 wind+load forecast errors cause imbalance 3 wind+load +production outages cause imbalances 4 other:
B	**Balancing location**	1 dedicated source 2 from the same region 3 also outside region 4 other:
U	**Uncertainty treatment**	1 transmission margins: 2 hydro inflow uncertainty: 3 wind forecasts: (a assume no knowledge and large margins for wind 0…full capacity b assume perfect forecast for wind, c persistence forecasts for wind d best available forecasts, specify what level of forecast error assumed) 5 load forecasts considered: 6 thermal power outages considered: 7 other: TIME HORIZON for forecasts assumed in the simulation (1–2 hours…day-ahead)
Power system details		
G	**Grid limit on transmission**	1 no limits 2 constant MW limits 3 consider voltage 4 N-1 criteria 5 dynamic simulation 6 other MULTI-AREA SIMULATIONS: limits inside the whole area and limits outside the simulated area separately
H	**Hydro power modeling**	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 hydrological restrictions included (reservoir level, stream flows) 4 availability of water, capacity factor, dry/wet year 5 hydro optimization considered 6 limited, deterministic run-of-river 7 interaction with hydro resources not significant 8 other:
T	**Thermal power modeling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered

		4 heat production considered 5 other:
W	**Wind power modeling**	1 time series: a – measured wind speed + power curve (how many sites) b – wind power from wind power plants (how many sites) c – re-analysis wind speed + power curve (how many sites) d – time series smoothing considered (how) 2 wind power profiles (a – climatic, e.g. lowest / highest temperature, b – hour of day, c – season, e.g. only winter, d – load percentile) 3 synchronous wind data with load or not 4 installation scenarios for future wind power distribution (put together scenarios by association, government plans; according to projected regional capacity factors…); specify geographical distribution of wind 5 other:

3.4 Finland/Nordic

3.4.1 Nordic reserve requirements

Estimate for the operating reserve requirement due to wind power in the Nordic countries is reported in (Holttinen, 2005 and Holttinen, 2004).

Results are presented in

Table 6.

- The increase in reserve requirements corresponds to about 2 % of installed wind power capacity at 10 % penetration and 4 % at 20 % penetration respectively. For a single country this could be twice as much as for the Nordic region, due to better smoothing of wind power variations at the regional level. If new natural gas capacity was built for this purpose, and the investment costs would be allocated to wind power production, this would increase the cost of wind power by 0.7 €/MWh at 10 % penetration and 1.3 €/MWh at 20 % penetration.
- The increase in use of reserves would be about 0.33 TWh/a at 10 % penetration and 1.15 TWh/a at 20 % penetration The cost of increased use of reserves, at a price 5–15 €/MWh would be 0.1–0.2 €/MWh at 10 % penetration and 0.2–0.5 €/MWh at 20 % penetration

Table 6. The increase in reserve requirement due to wind power with different penetration levels, as % of gross demand. The increase in reserve requirement takes into account the better predictability of load variations. The range in Nordic figures assumes that the installed wind power capacity is more or less concentrated.

	Increased use of reserves		**Increased amount of reserves**		
	TWh/a	€/MWh	%	MW	€/MWh
Nordic 10 % penetration	0.33	0.1–0.2	1.6–2.2	310–420	0.5–0.7
Nordic 20 % penetration	1.15	0.2–0.5	3.1–4.2	1 200–1 400	1.0-1.3
Finland 10 % penetration	0.28	0.2–0.5	3.9	160	
Finland 20 % penetration	0.81	0.3–0.8	7.2	570	

Input data, wind power modeling: synchronous, hourly data for wind power production and load for years 2000–2002. Many wind power time series, smoothing considered, but assumed to be fully incorporated in the data for 5 % penetration level up (no more smoothing effect with larger penetration levels). Danish data is real large scale wind power production data (time series of the sum of wind power production in the East and West DK). The increase in installed capacity has been taken into account when converting the data to unit "% of capacity" for up-scaling. Finnish data is mostly wind power production data from 21 sites. Swedish data is mostly wind power production data from 6 sites only (too few to represent Sweden). Norwegian data is mostly wind speed data from 6–12 sites only (too few to represent Norway). Stdev for time series of hourly variations was about 2 % (less for more dispersed and more for concentrated scenario).

Methodology: time series analysis of load forecast errors and wind power variations. Increase in hourly variations from load to net load, 4sigma used as confidence level. Load forecast dropping the load hourly variability to half. Existing reserves for disturbances have not been been considered, impact only estimated on operating reserves used for load following, no remaining generation system simulation.

Assumptions: Hourly data is assumed representative for 10–15 minute variations that determine the use of the secondary reserve (regulating power market) in the Nordel power system. 10–15 minute variations are less than hourly variations, so this is a conservative assumption. Prediction errors of wind power day-ahead have not been taken into account, imbalance calculation is for the operating hour only. This will underestimate the need for reserves, even if it is possible in the Nordel system that the producers or Balance responsible players correct their schedules up to the operating hour. No bottleneck situations limit the availability of reserves. Existing reserves for disturbances have been assumed not available for wind power, the impact is calculated on operating reserves only. The primary reserve requirement (seconds…minute) has been assumed to be very small.

Limitations: the result applies for the operating hour only. The prediction errors known 1–2 hours before operating hour are assumed to be balanced by the producers or balance responsible players as more accurate information on wind power production appears.

3.4.2 Nordic / efficiency of hydro thermal system

Simulations adding wind power to the Nordic power system are reported in (Holttinen et al., 2001 and Holttinen, 2004).

Results: In the Nordic power system with 46 TWh/a wind production (12 % penetration of gross demand), the losses due to increased bypass of water through the hydro power plants were 0.5–0.6 TWh/a, which is about 1 % of the wind power production.

Input wind data: wind speed measurement time series years 1961–1990: hourly time series (1) for Denmark. Daily time series (3) for Norway. Twice a day measurements (3) for Sweden. Weekly time series (1) for Finland. Wind speed was converted to power production by a wind turbine power curve (2 MW). Weibull distribution was used for data with daily/weekly averages.

Methodology: simulation with EMPS tool, Nordic countries. Review matrix is in Appendix 2 (Table A. 3).

Assumptions: hydro power will handle the in-week variations of wind power. Marginal prices of thermal power plants estimated to produce near real life Nordel system operation. Coal assumed in the margin, not gas.

Limitations: Weekly time scale does not take into account the variability of wind power. Static transmission limits do not take into account possible dynamic bottlenecks.

3.4.3 Finland balancing costs

The balancing costs for wind power producers in Finland for year 2004 were estimated in (Holttinen et al., 2006; Holttinen & Koreneff, 2007). The impact of wind power prediction errors to the system balancing costs of Finland were estimated in (Helander et al., 2009). Wind power prediction errors from predictions of 12 sites distributed over the West coast of Finland were upscaled to get prediction errors for up to 4 000 MW wind power (penetration 10 % of gross demand). The estimate was made to compare the balancing costs of wind power together with the associated system costs. Finland is part of the Nordic power market, where there is a balancing market for 15 min bids (called Regulating Power Market) that is used for frequency control coordinated by the 4 Nordic TSOs and this market sets the price used in balance settlement for all actors.

Results: The imbalance payments resulting from wind power prediction errors in day ahead (13–37 hours ahead) forecasts for year 2004 data ranged from 1.05 €/MWh for one site to 0.62 €/MWh for distributed wind power (12 sites, 680 km apart), with the two-price balance settlement system in use in Finland. The producer would benefit from intra-day market Elbas trade only if bids were available close to spot price levels to correct the prediction errors 1–2 hours before delivery. Year 2004 balancing prices were quite low. Since 2008, two-price system is used in the Nordic countries for production imbalances and one price system for consumption imbalances. The imbalance prices for distributed wind power were calculated for both one- and two-price system. One price system would benefit wind power producer, especially if the production is not distributed but comes from a single site with higher prediction errors than used here for distributed, future wind power.

The increase in system costs was calculated using the net system imbalance time series of Finland (Fig 19). The difference between the system imbalance price before and after adding wind power prediction errors was the increase in system cost due to wind power. The first MW's of wind power will not have any correlation with the system net imbalance and need for balancing, thus about 50 % of time the wind imbalance will be to the opposite side of system imbalance and no costs occur. However, as wind power increases the wind power imbalances start to impact the system imbalance and thus more of the time wind power imbalance will be to the same side as system imbalances (both either up- or down-regulation).

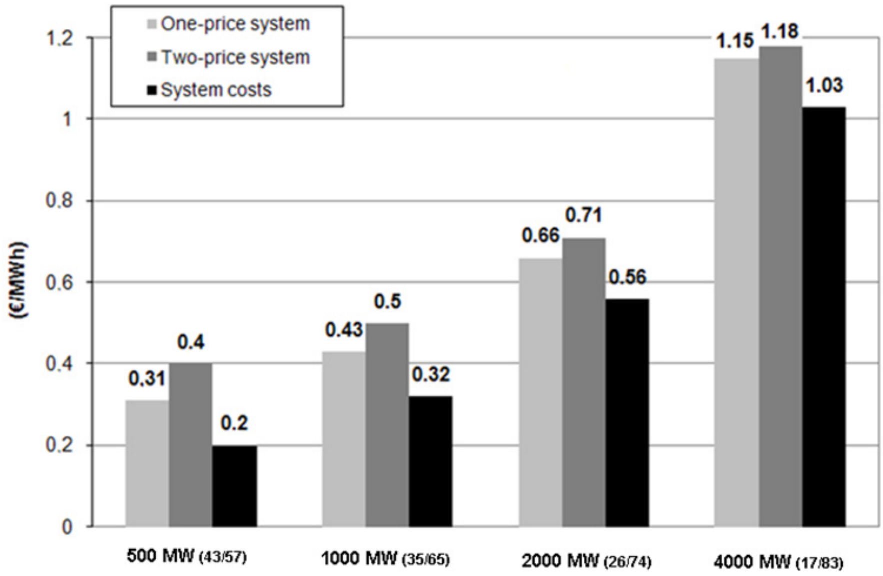


Fig 19. Comparison between payments for wind power producers and system costs. It is assumed that bottlenecks to Nordic balancing market do not occur and all costs are calculated using linear relations (-0.015xQ and 0.011xQ) between regulation power price and quantity to determine regulation power price. Volume costs of 0.7 €/MWh are added for wind power producers. The results for one/two-price system are for a distributed wind power in Finland – for a producer with a single site the costs would be higher.

Input wind data: Wind power predictions were calculated for 12 sites distributed over the West coast of Finland with a time series prediction model for year 2004. When estimating the system costs, to get results for future prediction errors, a time series of 3 hours ahead predictions was used instead for day-ahead (13–37 hours ahead) prediction. The prediction error was on average 5.3 % of installed capacity (MAE). Average (absolute) error of 5.3 % corresponds to 21 % of average power, or yearly energy. These prediction errors were upscaled to get an hourly time series of prediction errors for up to 4 000 MW wind power (penetration 10 % of gross demand).

Methodology: Wind power prediction errors for 500/1 000/2 000/4 000 MW wind power for year 2004 were combined with hourly data of system net imbalances of Finland in year 2004 to get the total demand (quantity) for balancing at the Regulation Power Market. All costs for up- and down-regulation prices are calculated using linear relations (-0.015xQ and 0.011xQ) between regulation power price and quantity to determine regulation power price. The increase in system costs was calculated using the net system imbalance time series of Finland. The difference between the system imbalance price before and after adding wind power prediction errors was the increase in system cost due to wind power.

The same calculation was made using as prices the average up- and down-regulation prices of 2004. Using linear formula for the prices produces somewhat higher costs compared with year 2004 average up- and down-regulation prices. Year 2004 regulation prices were at a lower level compared with later years.

Assumptions: The linear price assumption is very rough. This can be used as a comparison for what wind power pays as balancing costs, calculated with same procedure. But it does not give right level of costs as €/MWh.

Limitations: The impact of wind power prediction errors on regulation market prices and thus cost of balancing was estimated in a very rough way.

3.5 Denmark

3.5.1 Nordic + Germany

A stochastic, linear optimisation model specifically aimed at taking wind power forecast errors into account when optimising unit commitment and dispatch of power plants was developed in the WILMAR project (http://www.wilmar.risoe.dk). A study with the Wilmar Planning tool done in the EU project Greennet-EU27 (Meibom et al., 2009) estimated increases in system operation costs as a result of increased shares of wind power for a 2010 power system case covering Denmark, Finland, Germany, Norway and Sweden combined with three wind cases. The base case has a "most likely" forecast of wind power capacities in 2010 for all countries. For Finland, Norway and Sweden wind power capacities equal to cover 10 % and 20 % of the annual electricity demand are used in respectively the 10 % and 20 % case. For Denmark and Germany forecasted wind power capacities for 2015 (equal to cover approximately 29 % and 11 % of the annual electricity demand, respectively) are used in both the 10 % and 20 % cases. The integration costs of wind is calculated as the difference between the system operation costs in a yearly model run with stochastic wind power forecasts and the system operation costs in a yearly model run where the wind power production is converted into an equivalent predictable, constant wind power production during the week. If the realised wind power production in one week has a positive correlation with the load variations, it can happen that in fact in this week the integration costs are negative. Fig 20 shows the results distributed on countries using an approximate algorithm to distribute system costs among countries (see Meibom et al., 2009).

Results:

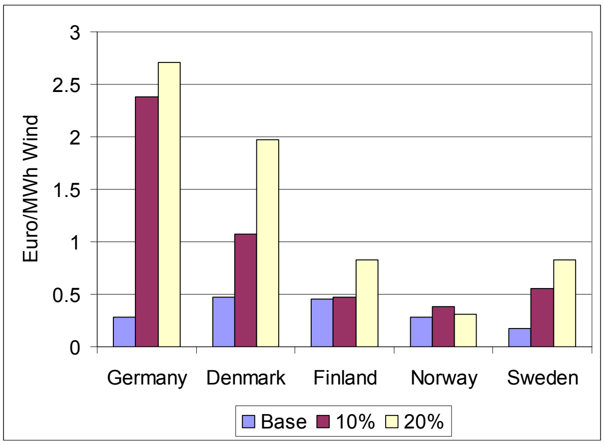


Fig 20. Increase in system operation costs per MWh wind power production for three wind cases (base, 10 %, 20 %) and divided on countries.

The following conclusions could be drawn from the study:

- For the 10 % and 20 % wind cases, wind integration costs are highest in Denmark and Germany dominated by thermal production, whereas they are lowest in the hydro dominated Norwegian system. The reason is that hydropower production has very low part-load operation and start-up costs and hydro-dominated systems are generally not constrained in regulating capacity.
- In the base case Finland, Norway and Sweden have relatively small yearly wind power productions (respectively 1.1 TWh, 3.4 TWh and 2.3 TWh) with corresponding small changes in operational costs between stochastic, deterministic and constant model runs. The approximate approach to dividing operational costs between countries therefore influences results more than in the 10 % and 20 % cases. This might explain the relatively high wind power integration costs for Finland in the base case compared to the 10 % case.

- Norway has a power system extremely suitable for integrating wind power consisting of flexible hydropower. Results show low wind power integration costs in Norway that are approximately constant when expressed relative to wind power production for the cases considered. The slight decrease in integration costs for Norway from the 10 % to the 20 % case must be attributed to uncertainties when comparing different wind cases.
- The wind power integration costs increase when a neighboring country gets more wind power. Germany and Denmark have the same amount of installed wind power capacity in the 10 % and 20 % cases, but the integration costs of Germany and Denmark increase from the 10 % case to the 20 % case, especially in the case of Denmark. The reduction in operational costs caused by the exported wind power production depends on the short-term production costs of the marginal unit in the importing country. As domestic wind power production increases, it displaces the more expensive production plants thereby reducing the short-term production costs of the marginal unit This effect causes the exported wind power production to have lower value for the importing country, and consequently generating a lower revenue to cover the costs of wind power in the exporting country.

Input data, wind power modeling: Historical hourly wind speed and wind power production time series for 2000–2002 aggregated and converted into hourly wind power production time series for each region in the model. Denmark: Historical hourly, total wind power production data for East and West Denmark. Finland: Historical hourly wind power production time series for 21 sites. Germany: Historical hourly wind speed time series for 10 sites. Norway: Historical hourly wind speed time series for 6–12 sites. Sweden: Historical hourly wind power production time series for 6 sites.

Methodology: WILMAR model for the Nordic/Germany area. Review matrix is in Appendix 2 (Table A. 4).

Assumptions: Perfect market assumption i.e. power producers will produce when prices become higher than short-term marginal production costs (mainly fuel costs), and there will be no exercise of market power. Usage of transmission capacity between model regions co-optimised with usage of production capacities, i.e. no possibilities for reservation of transmission capacity by specific market actors before the daily operation takes place. All production capacity is available for the balancing of wind power production except the capacity restricted by start-up times or other technical constraints. This corresponds to assuming a very liquid regulating power market. Linear approximation of unit commitment allowing that any amount of additional capacity can be brought online, as long as the amount is smaller than the available capacity, thereby avoiding the usage of integer variables. The linear approximation is not as problematic as it sounds in a model where individual power plants anyhow are aggregated into unit groups, such as for the large model area analysed in this study.

Limitations: Load uncertainties and stochastic outages of power plants were not included in the model at the time of the study.

3.5.2 Energinet.dk 50 % wind study

To fulfil the ambitious Danish government's energy policy for 2025 (Danish Energy Authority, 2007), Danish TSO Energinet.dk plans for a doubling of presently about 3 000 MW installed wind power to about 6 000 MW before 2025 (Energinet.dk, 2007; Eriksen & Orths, 2008). About 2 000 MW is expected to be installed offshore. The change corresponds to a future increase from 20 to 50 % of wind penetration (of gross demand).

The investigations focus on evaluating the challenges of this large addition of wind power in the Danish power system. Assessments are made for the energy balance, the fuel consumption, the emissions, the power balance, the need for ancillary services and the transmission grid. The integration of 50 % wind energy into the electricity system places strong demands on flexibility in the system. This applies to production, grid and consumption. A list of means is described.

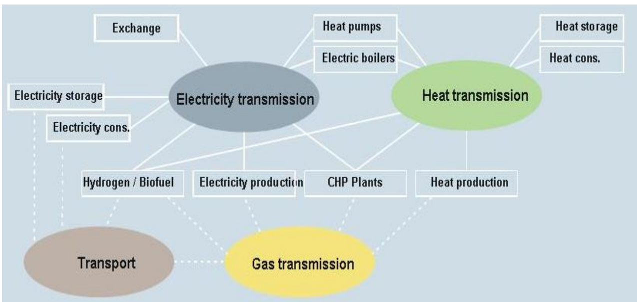
Two alternatives have been calculated, with varying exchange capacities in the year 2015, table 2. Alternative 0 shows the variant with today´s capacities, resp. the ones which are decided. Alternative 1 assumes increased interconnections both in the North and South of Jutland, as well as an increased Great Belt connection, see Table 7.

Table 7. Two cases with assumptions concerning interconnections.

	Alternative 0	Alternative 1
Great Belt	600 MW	1 200 MW
Germany – Western Denmark	Imports: 950 MW Exports: 1 500 MW	2 500 MW
Norway – Western Denmark	1 000 MW	1 600 MW

Results: The investigations have shown that a further large scale integration of wind power calls for exploiting both domestic flexibility and international power markets. Both means are prerequisites for maintaining security of supply and maximising the economic value of wind power, and they are strongly connected to the provision of system service. This is not a question of one single measure, but the combination of a bigger package is essential. Measures of large-scale wind power involve measures on the market side, on the production side, on the transmission side and on the demand side.

Utilizing and further development of couplings of the wind power dominated electricity system to district heating systems, the transport sector (e.g. via electric vehicles) and energy storage systems are vital for future successful large- scale wind integration. The combination of these measures will continuously be investigated in more detail.



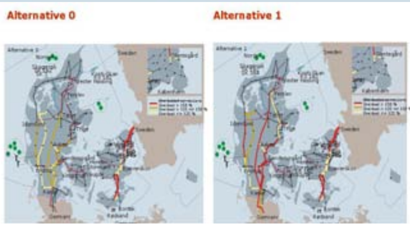


Fig 21. Congestions at both alternatives (Alternative 1 increased interconnection capacity).

The congestion-related result is shown in Fig 21. It is obvious, that an increased transit through Jutland will lead to overloading of lines, if no countermeasure is taken. Countermeasures could be implemented on several sides of the power system:

- At the market side market coupling (e.g. NordPool-EEX etc.) to increase the possibilities of sharing reserves, improvement of intraday trading possibilities and international exchange of ancillary services.
- At the electricity production side: Utilization of an electricity management system for wind power plants, which regulates the generation, geographical dispersion of offshore wind farms, mobilizing of regulating resources and new types of plants and further improvement of local scale production units working on market terms.
- At the electricity transmission side: reallocation of the grid connection point for offshore wind power plants, increased grid transmission capacity, e.g. including the utilization of high temperature conductors, and reinforcement and expansion of the domestic grid and interconnections.
- At the demand side: further development of price dependent demand, utilize and strengthen the coupling of the power system to heating systems: electric boilers and heat pumps, develop and exploit coupling of the power system to the transport sector (electric vehicles as price dependent demand), and introduction of energy storage: hydrogen, Compressed Air Energy Storage (CAES), batteries.

The measures mentioned above are investigated by the Danish TSO and partners in research and development to enable the “plus 3 000 MW” scenario 2025.

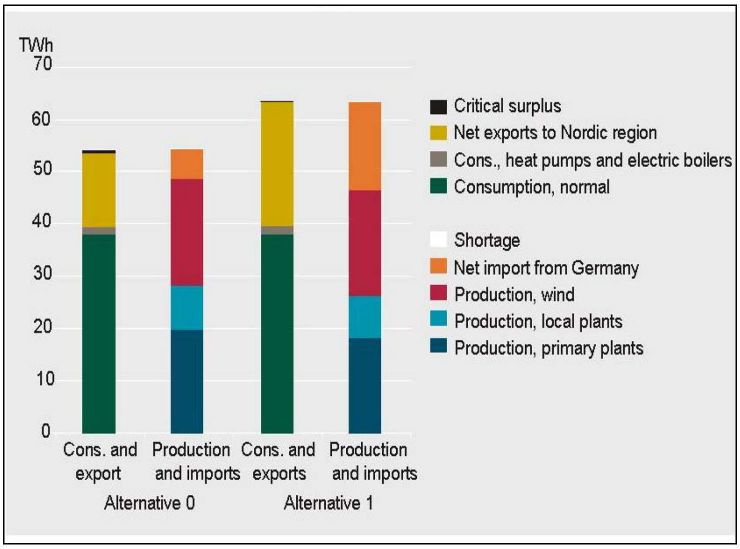


Fig 22. Energy Balances at both Alternatives (Alternative 1 has increased interconnection capacity).

Fig 22 shows the results related to energy balance. For alternative 1 the Danish system faces a higher northbound transit, while the production of primary plants is slightly decreasing (Energinet.dk, 2007).

Thus, the emissions of these two alternatives are very similar for Denmark, but seen in a larger (European) frame, it will make a difference if large scale wind power is implemented in the power system. Already today new solutions have to be prepared with respect to system operation. And these solutions should be well coordinated with respect to sustainability and variability for future developments, nationally as well as internationally.

Input data, wind power modelling: The scenario which describes the governmental energy strategy for the year 2025 deals with a slight increase of demand from 35 TWh (2005) to 38 TWh (2025) – even with strengthened savings. Concerning production facilities a power generation capacity with 6,400 MW thermal power stations and 6,500 MW wind power capacity was simulated (Fig 23). Measurement based time series of wind power over a year have been used and scaled up to the expected level, taking into account the geographical spreading and grid connection points.

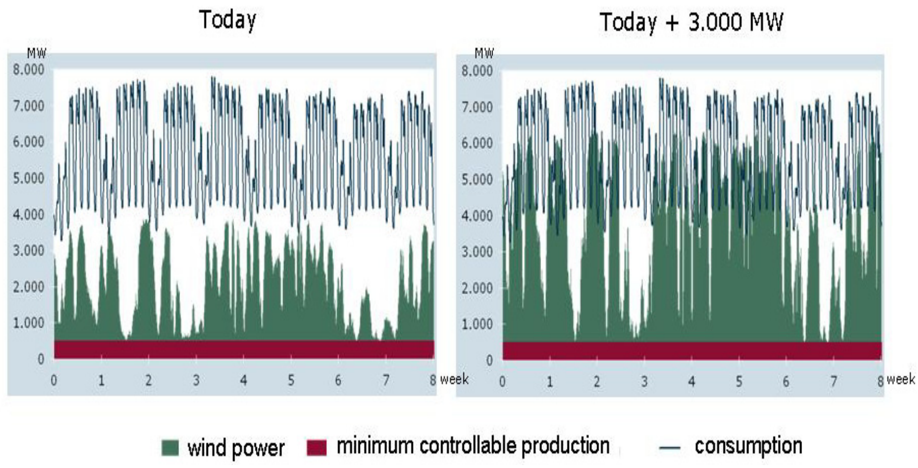


Fig 23. Wind Power Production Today and Expected Level in 2025.

Methodology: Two simulation tools have been used: "Sivael" and "PowerFactory". Fig 24 gives an overview over the methodology which aims at providing an optimal grid structure. First, the data and assumptions on production, consumption, fuel prices, production characteristics of different units, electricity prices in neighboring areas and exchange capacities between all Nordic countries and to the continent are fed into a simulation tool (SIVAEL). This tool optimizes the hourly schedule of the Danish heat and electricity system, minimizing the total operation cost. The output is the power balances for every hour of a year, the costs, environmental data, exchange data etc. These power balances are fed into a loadflow calculation tool, which delivers the respective results and enables the TSO finally to make some statistical evaluations on appearance of congestions or to execute variant calculations e.g. with respect to the effect of offshore connection point variants.

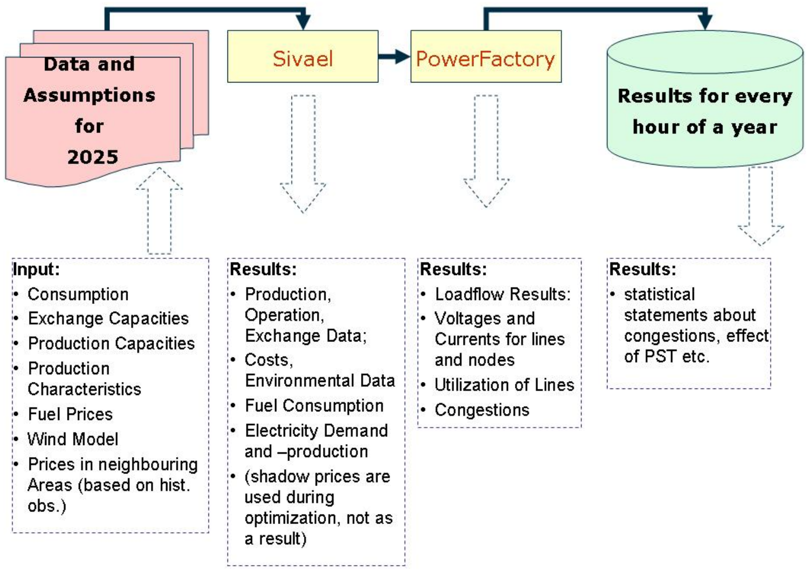


Fig 24. Overview over the methodology.

Assumptions: The prerequisites for the simulations are based on the Danish Energy Strategy with respect to the relevant scenario, and on IEA's World Energy Outlook with respect to fuel prices.

Limitations: Aspects of network operation have not been investigated in this study, but play a decisive role. These aspects are currently investigated in further detail.

3.5.3 Denmark: increasing flexibility

(Lund & Münster, 2006) evaluate the ability of heat pumps and electric boilers to increase the flexibility of a power system with a high share of CHP and wind power production. The model they use, EnergyPLAN, is a deterministic simulation input/output model of Western Denmark with the rest of the Nordic power system treated as a price interface to Western Denmark. They find high feasibility of investments in flexibility especially for wind power production inputs above 20 % of the electricity consumption.

3.6 Sweden

3.6.1 Reserve requirements, Elforsk 2005

Report: 4 000 MW wind in Sweden (Axelsson et al., 2005).

Results: The results are in Table 8. The report neither estimates whether this increase in reserve requirements could be met with existing capacity, nor estimates the cost of increased use of reserves. To estimate how much potential bottleneck situations could affect the results, the same calculation has been made for different regions in Sweden.

Table 8. Results of increased reserve requirements in Sweden for different wind power penetrations and different time scale reserves.

Installed wind power MW	Penetration level %	1 hour stand. dev. MW (%)	4 hours stand. dev. MW (%)	Day-ahead Max. positive MW (%)	Day-ahead Max. negative MW (%)
4000	6.6	20 (0.5)	195 (5.0)	690 (17.2)	590 (14.8)
6000	9.9	45 (0.75)	-	1350 (22.5)	1030 (17.2)
8000	13.2	80 (1.0)	-	1570 (19.6)	1220 (15.2)

Input data, wind power modeling: The wind power production input is from a synthetic time series for years 1996–2001, coinciding with the load data. Load forecasts were available for 2002–2004 indicating RMSE forecast error of 1.5 % for short-term forecasts (1–24 hours) and around 5 % for forecasts one week ahead. Wind power forecasts were assumed reducing the variability to 80 % of persistence for one hour ahead (from 1.8 % to 1.4 % of installed capacity). For 4 hours ahead, the same level of forecast errors as in Germany were used (2.5 % of installed capacity). For day-ahead, German data was scaled for Sweden.

Methodology: The methodology for 1 and 4 hour calculations is the same as in section 3.4.1 (Holttinen, 2004), except that also wind power predictability has been taken into account. It can be noted that "stand. dev." in table 7 means that a probabilistic method using 4σ is applied. For day-ahead, the methodology of 3.7.1 (Dena, 2005) has been used, by scaling the German results to Sweden assuming similar predictability of wind power. In the report (Axelsson et al., 2005) it is stated concerning the use of Dena results that "….the figures for Sweden … can probably be considered as an upper limit. It must once again be noted that also for Sweden these figures relates to the extra requirement during high wind situations”.

3.6.2 Reserve requirements – SvK 2008

Report: Large scale expansion of wind power – Consequences for the transmission grid and need of regulation power (Svenska kraftnät, 2008).

Results: The amount of needed regulating resources has been estimated based on the report (Axelsson et al., 2005). The results are shown in Table 9. It can be noted that the presented amounts are higher than in other reports and the reasons are explained below.

Table 9. Need for additional reserves in Sweden at 4 000–12 000 MW of wind power (Svenska Kraftnät, 2008).

Type of reserves	**4 000 MW wind power**	**12 000 MW wind power**
Additional primary reserves	200–250 MW	600–750 MW
Additional reserves needed in order to compensate for wind power forecast errors	500–600 MW	1500–1900 MW
Additional reserves in order to compensate for wind power outages at storm fronts	700–900 MW	2 200–2 700 MW
Total need of additional reserves	1 400–1 800 MW	4 300–5 300 MW

Input data, wind power modelling: There are no new data studied in comparison with the ones used in (Axelsson et al., 2005). However, the results differ significantly depending on other methods used which interpret the result differently.

Methodology: *The additional primary reserves* are calculated in the following way: From the report (Axelsson et al., 2005) the figure for “Increase in maximum hourly variation (MW)” is used, i.e., how much the net load (load minus wind power) changes between two hours will increase. The figure for 6000 MW wind power is that maximum increase of net load will increase with 199 MW (from 2383 MW to 2582 MW) and maximum decrease of net load will increase with 552 MW (from –1331 MW to –1883 MW). The mean value for positive and negative “maximum change” is then (199+552)/2= 375.5 MW. At an assumed production level of 90 % of 6000 MW = 5400 MW the "maximum change" corresponds to 7 % of the assumed production level. The "90 % production level" and "7 %" are then used to calculate the upper limit of additional primary reserves (0.07*4000*0.90=250, 0.07*12000*0.90=750). The lower level is set based on an assumption of uncertainties in the calculation method.

The *additional reserves needed in order to compensate for wind power forecast errors* are based on (Axelsson et al., 2005) where it is stated that in a situation with 4000 MW of wind power the "Day-ahead Max.negative" forecast is 590 MW the "Day-ahead Max.positive" forecast is 690 MW. The mean value is 640 MW corresponding to 16 % of 4000 MW. At an assumed level of 90 % of 4000 MW, this means a mean day-ahead forecast error of 0.90*0.16*4000 = 576 MW which in the table is written as 500–600 MW. For a wind power level of 12000 MW, the same method is applied: at 90 % of 12000 MW means a mean day-ahead forecast error becomes 0.90*0.16*12000 = 1728 MW which in the table is written as 1500–1900 MW.

The *additional reserves in order to compensate for wind power outages at storm fronts* are estimated as follows: For the upper level a 90 % production level in assumed, and out of this a storm front can affect 25 % of the production. This leads to possible outages of 0.25*0.90*4000 = 900 MW and 0.25*0.90*12000 = 2700 MW respectively. The lower level is set based on an assumption of uncertainties in the calculation method.

Comments to methodology: The report has used data and results from (Axelsson et al., 2005) but they have interpreted the results in a different way. Concerning *additional primary reserves* for the case 4000 MW of wind power (Svenska kraftnät, 2008) states 250 MW, while (Axelsson et al., 2005) states 20 MW. The reason is not different data, but different methods. In the following only the direction of reserves for "net load increase" will be shown as an example since "reserves which can increase production" is a generally larger challenge than "reserves which can decrease production". (Svenska kraftnät, 2008) uses "maximum net load change between different hours" as the basic data, even if it is for estimating the primary reserves, in seconds time scale. It must be noted that without wind power the maximum load change in an hour is +2383 MW. And without wind power the requirement for primary reserves in Sweden is 235 MW. With 4000 MW of wind power the "maximum net load change between different hours" increases with +199 MW, corresponding to an increase of 199/2383 = 8.35 %. If the required amount of primary reserves should be based on "maximum net load change between different hours", then the required amount of primary reserves should increase with 8.35 %, corresponding to 21 MW, which is very close to (Axelsson et al., 2005). This means that the method resulting in a need of 250 MW leads to a significant overestimation of these reserves.

Concerning the *additional reserves needed in order to compensate for wind power forecast errors* the extra requirements are based on day-ahead forecast errors. It must though be noted that the forecast quality improves when one comes closer to a certain hour. The reserves that have to be kept in a system must be scheduled so much in advance so their ramp rates can follow the imbalances caused by forecast errors. In most systems the slowest units can be started up in some hours. In the Swedish/Nordic system the main part of the reserves is hydro power plants which can go from stand still to full production in minutes. From the physical point of view (enough capacity on-line) it is then not the 24 hour forecast errors that are of interest but more the 3 hour forecasts for many systems (start-up time of 3 hours) or 1 hour forecasts in the Swedish/Nordic system. The 24-hour forecast errors are interesting from the market point of view (volumes that have to be traded outside the day-ahead market) but can not be used to estimate required physical MW-margins. The use of 24-hour forecast errors leads to an overestimation of required forecast error reserves.

Concerning the *additional reserves in order to compensate for wind power outages at storm fronts*: In the basic data used in (Axelsson et al., 2005), wind speeds from several places and a certain wind power plant model (cut-out wind speed 25 m/s) have been used. This means that in the resulting wind power production series, also outages depending on storm fronts are included. In (Svenska kraftnät, 2008) a 25 % outage is assumed. Of course a 25 % decrease in production is possible; the question is though how frequently this happens, the quality of forecasts and if this means requirements of "additional reserves". In (SMHI, 2004), data used in (Axelsson et al., 2005) are presented. In (SMHI, 2004) it is stated that "Statistics show that a loss of capacity of 50 per cent during a six-hour period happens once a year on average". This means that loss of 25 % of capacity probably takes 2–3 hours and happens, probably, 1–4 times per year. This means that power plants with enough ramp rates have to be on-line to compensate for this power production decrease. Svenska kraftnät (2008) do not consider the possibilities of using forecasts of outages at storm fronts, and it can be noted that the results mean that more reserves are needed for possible changes in 2–3 hours (*storm front outages*) than what is needed in 24 hours (*compensation for wind power forecast errors*). If forecasts are not considered then this leads to an overestimation of needed reserves to manage outages caused by storm fronts.

Concerning *total need of additional reserves* the results are obtained using the method of adding the three types of reserves. It must then be noted that the two last types of reserves have a very strong interaction since one do not keep these reserves in different units. It can not be rational to keep margins for possible changes within 3 hours in some units and at the same time, in other units, keep margins for what could happen in 24 hours. This means that the method of adding these three types of reserves gives an overestimation of required reserves.

As stated in section 3.2: In a situation with high wind power production, i.e., a situation with possible decrease of wind power production, other units are not in operation (since some of the load is met with wind power). This means that these units can increase their production if wind power decreases and/or load increases. The consequence is then that it is very common that needed reserves for wind power decrease are often available in the same way as power plants are available in a low load situation to meet load increase. In (Svenska kraftnät, 2008) there is no study concerning the coupling between needed reserves and the availability of these. This will require much more detailed studies of the future system.

In the report the total costs of reserves is estimated as the calculated total amount of reserves multiplied with the costs per MW that the TSO currently pay for the peak load capacity (capacity costs for production units and flexible loads used, perhaps, some single hours per year). This results in an overestimation of the cost since the total amount of reserves is overestimated. If these reserve units need any kind of "subsidy" (as peak load capacity) depends on how the prices are set on the market. There are currently no capacity payments at all to operating reserves in Sweden.

3.6.3 Imbalance costs for wind power producers

Report: "A massive introduction of wind power. Changed market conditions?" (Neimane & Carlsson, 2008.)

Results: In this report eight different actors have been created, that all have balance responsibility for their production, which means that if they cause an imbalance they have to pay up or down regulating prices. These actors are different in the sense that some are small and some are big, some have concentrated wind farms and some have wind farms that are geographically spread-out. In the study the imbalance costs for these actors have been estimated for a future scenario with larger amounts of wind power. The result is shown in Fig 25, where Elbas is the intra-day market closing one hour before delivery, for each hour. It is assumed that wind power will increase with 4000 MW compared to 2006. This implies that the total imbalance will increase from 0.95 TWh/year to 1.7 TWh/year.

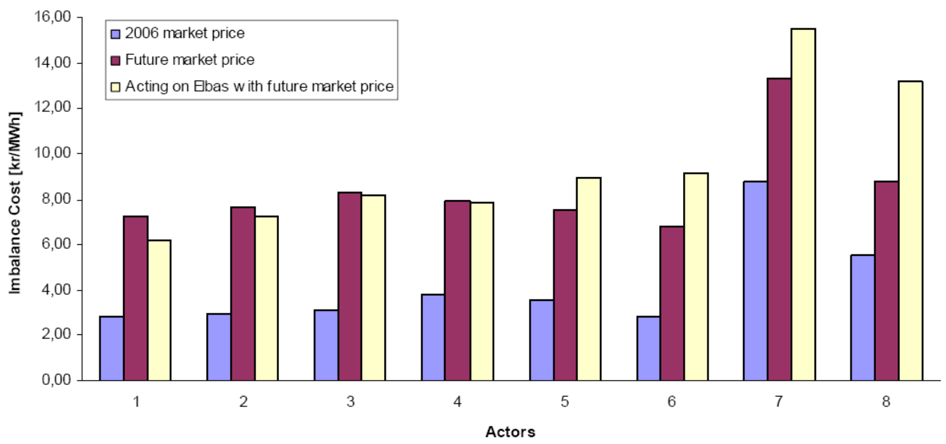


Fig 25. Comparison on the cost of forecast errors on a) the 2006 market, b) the future market and c) future market and acting on Elbas. 1 SEK = 0.1 Euro.

Input data, wind power modelling: Forecast error data from the 160 MW wind power farm Horns Rev for the period 11 September 2006 to 31 March 2007 has been made available for this study, but the data is used taking limited forecast error correlations into consideration. Regulation prices for the year 2006 are used

Methodology: To calculate the cost of the forecast errors, a developed price model by Klaus Skytte at Risø Laboratory in Denmark has been used. This model has parameters that have been estimated for the market situation during 2006. By generating the forecast errors for all actors as random numbers with normal distribution in Excel for a whole year, it has been possible to calculate the actors' cost for their forecast errors. It can be noted that imbalance costs are paid between different market actors, and one can not draw the conclusion that an increased imbalance cost automatically corresponds to an increase of total cost.

3.6.4 Increase in the use of reserves

Report: Future trading with regulating power, (Brandberg & Broman, 2007).

Results: The purpose has been to investigate how the Nordic regulating power market will react to integration of 4000 MW of wind power in Sweden. Results from this study by using two different methods are presented in the table below.

	No wind power	4000 MW Method 1	4000 MW Method 2
Regulating power [GWh]	2279	3566	2680
Turnover on Elbas [GWh]	2490	4010	-

Input data: Data from 2003 for the West Danish power system with an installed wind power capacity of 2400 MW have been used. The data consists of 24-hour and 4-hour forecasts and actual production of wind power.

Methodology: The method used for investigating the impact on the regulating market prices is by studying the impact of wind power forecast errors. The forecast errors for wind power production have been added to historical regulating quantities and the new prices have been estimated according to the new regulating power quantity levels. Wind power production forecast errors have been estimated in two different ways:

1. The forecasts errors have been calculated and scaled up to reflect an installed capacity of 4 000 MW of wind power. The 24-hour forecast errors have been used to estimate the increase of adjustment power on the Elbas market, and the 4-hour forecast for increase of regulating power.

2. Calculation of forecast errors by setting the forecast errors to the change in production between the hour prior to the hour of operation and the hour of operation. This forecast error has also been calculated for the Danish data and scaled up to 4000 MW.

3.6.5 Efficiency of hydro power

Integration study of small amounts of wind power in the power system (Söder, 1994).

Results: Swedish wind power installations of about 2–2.5 TWh/year do not affect the efficiency of the Swedish hydro system. At wind power levels of about 4–5 TWh/year the installed amount of wind power has to be increased by about 1 % to compensate for the decreased efficiency in the hydro system. At wind power levels of about 6.5–7.5 TWh/year the needed compensation is probably about 1.2 %, but this figure has to be verified with more extended simulations.

Input data, wind power modeling: Many generated power series based on stochastically generated wind speed forecast errors.

Methodology: Wind power balancing was performed in one river using a detailed model including station efficiencies and the result was upscaled to Sweden. Deterministic planning but evaluation based on stochastic forecast errors. The "integration cost" was calculated as needed extra energy (MWh) to compensate for lost hydro energy. The weekly load was increased in order to compensate for mean wind energy increase. Load and wind uncertainty were treated. Wind power was increased until evaluation strategy did not work. Review Table is in Appendix 2.

Assumptions: Best available wind speed forecasts (in 1994) assumed available. Rescheduling of hydro plants assumed every hour to consider new improved wind speed forecasts. Full access to a grid assumed, i.e., no limitations and 100 % reliable.

Limitations: All Swedish wind power assumed to be balanced only with Swedish hydro power. Trading with neighboring systems and thermal power operation assumed unchanged. Results origin from study of a smaller part of the Swedish system and scaled up to be representative. Changes in electrical grid losses not considered.

3.7 Germany

The German Energy Agency (Dena) commissioned the study "Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020" (Dena Grid study). The goal of this study was to enable fundamental and long-term energy-economy planning, supported by associations and firms in the sectors of wind energy, grid and conventional power plants.

Scenarios for the increased use of renewable energy sources for the years 2007, 2010, 2015 and 2020 were geographically differentiated for wind power development onshore and offshore, with the assignment of wind power feed-in to particular network nodes. Based upon these scenarios, the effects of wind power feed-in on the transmission network and on the conventional generation plants were investigated.

The results of the study show, that the planned share of at least 20 percent of renewable energy in power generation in Germany with high amount of wind energy is achievable. However, the precondition for this is the implementation of the measures shown in the study in regard to the development of the transmission system. This wind power is in line with the target of a 20 % share of all renewable energy in the German electricity supply that the Federal Government wants to achieve by 2020 at the latest. Within the given framework conditions of the study it would only be possible to draft technical solutions for the integration of renewable energy sources into the existing power system up to a share of approx. 20 % in electric power generation (5 % offshore-wind, 7.5 % onshore-wind, and 7.5 % other renewable sources). A further major increase in geographically concentrated offshore wind power plants in Northern Germany, as it is planned after 2015, would require a more extensive investigation to develop viable technical solutions.

The results of the Dena grid study as well as the developments in the wake of the study on the increase in balancing needs are presented in this chapter and the results on grid and adequacy in following chapters.

3.7.1 Dena study / reserves

Results: The forecast errors for wind energy give rise to an additional requirement for regulating and reserve power capacity to guarantee the balance between infeeds and loads at all times. Despite an assumed improvement in the predictability for wind energy, the required regulating and reserve power capacity increases disproportionately as the installed wind capacity increases. Due to the dependency of the wind-related regulating and reserve power capacity requirement on the level of the predicted wind infeed, the regulating and reserve power capacity required for the following day can be determined in dependency on the forecasted wind infeed level, taking into account optimisation aspects. This provides an average “day ahead“ regulating and reserve power capacity. The additionally required regulating energy could be provided by the existing conventional power stations. However, the power stations must be collectively configured in order to provide the required maximum regulating and reserve power capacity at all times. For 2015:

- Additional maximum 7,064 MW of positive regulating and reserve power capacity is needed, of which on average 3,227 MW has to be contracted “day ahead” (9 % of wind power capacity). In 2003, the corresponding values were 2,077 MW maximum and 1,178 MW on average.

- Additional maximum 5,480 MW of negative regulating and reserve power capacity is needed, of which on average 2,822 MW has to be contracted “day ahead” (8 % of wind power capacity. In 2003, the corresponding values were 1,871 MW maximum and 753 MW on average.

Input data, wind power modeling: many wind power time series, from reference sites to 10–10 km areas covering Germany Data of wind speed and wind direction from up to 220 measuring points in Germany for the years 1992 to 2003 with sampling rate of 10 Hz in 10 m 30 m and 50m hight were used to calculate wind power generation time series with 5 minute invervals for 7 years.

Methodology: in the calculation of the control/reserve requirements the probability distribution of the forecast errors of the wind power infeeds as well as those of the forecast errors of the load demand were considered. Together with the probability distribution of the power deficit caused by stochastic power plant outages a probability distribution of the power system power deficit/surplus was derived. This probability distribution was the input parameter for the calculation of the necessary control/resreve power provision (calculation was carried out for one year).

Assumptions: day-ahead forecasts for wind power, no updates closer to the operating hour considered**.** Assumed development of hub hight in the year 2010: 90 m onshore, 100 m offshore and in the year 2015: 100 m onshore, 110 m offshore.

Key figures for the distributions of the day ahead and 4 h forecast errors are shown for the years 2003, 2007, 2010 and 2015 in Table 10.

Table 10. Key figures for the forecast quality of the day ahead and 4h WT forecast in percentage (%) of installed capacity, 2003–2015 (Dena, 2005).

	day ahead wind forecast				**4-hour wind forecast**			
	Average	Standard deviation	Min.	Max.	Average	Standard deviation	Min.	Max.
2003	-0.28%	7.29%	-27.5%	41.5%	1.26%	4.92%	-17.0%	33.0%
2015	-0.32%	5.91%	-23.5%	29.5%	0.97%	3.89%	-14.0%	24.3%

Values of 0.1 % deficit probability for positive and negative regulation and reserve capacity for individual contractual zones (approx 8.76 hours per annum) were assumed. Sensitivity analyses were carried out with 0.01 % (approximately 52 minutes per annum) and 0.0025 % (approximately 13 minutes per annum) deficit probabilities. The influence of the deficit level on the additional, wind-related regulation and reserve power demand was marginal compared to the influence of the development of installed wind turbine capacity between 2003 and 2015.

3.7.2 Studies after Dena

The Dena Grid study was a milestone in the public and political awareness of the challenges of grid integration of wind power in Germany. The results of the study were accepted by the wind industry as well as the grid operators. Some of the conclusions of the Dena grid study were integrated into the new German Renewable Energy Act, which comes into force 1. January 2009.

One of the aspects of the Dena Grid Study tackled in the new German EEG 2009 is the improvement of the behavior of wind turbines in the grid. The payment of the power production will depend on the compliance with technical requirements to the grid integration and the behavior of the turbines in the case of a grid fault. A study has been performed to support the BMU in the legislative provision (Bömer and Burges, 2008). The study developed a proposal for technical requirements for the legal provision based on the latest grid codes. It has been estimated that the additional generation cost will be between 0,3 and 0,47 ct/kWh. Also guidelines for the proof of compliance have been developed based on type certificates and grid calculations.

The German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) also commissioned a study to investigate the optimization potential for the integration of wind energy into the German electricity grid (FGE/FGH/ISET, 2007). The BMU has selected a number of approaches, which have been investigated in the study with respect to their potential to improve the integration of wind power into the electricity supply system. The aim was not to quantify the effect of the different approaches, but to identify relevant and promising solutions. The investigations are based on the wind power scenario of the year 2020 of the Dena Grid Study.

The study investigated the potential for improvement of the wind power integration by creation of an intra-day market. The use of an intra-day market reduces the need for reserve power and balancing energy in the minute reserve due to the reduced forecast error for wind power production. This concept relies on the liquidity of the intra-day market to secure the balancing needed. Currently the trading volumes of the European intra-day markets is too small.

For the assessment of the economic benefits of the use of the intra-day market for wind power integration current prices for reserve power (positive: 82 k€/MWa and negative 26 k€/MWa) and balancing energy (positive: 120 €/MWh and negative 0 €/MWh) were assumed. For buying power on the intra-day market, the mean spot market price (45 €/MWh) was assumed, based on the actual behaviour of the European intra-day markets. For selling power on the intra-day market no revenue (0 €/MWh) was assumed. Based on these assumptions no significant advantage of the use of the intra-day market for wind power integration was found.

An assessment of the potential benefit of pooling the balancing need due to wind power and load forecast errors and of pooling the errors for the four German TSO was performed. The result depends highly on the correlation of the load forecast errors of the different TSO control zones, which was not estimated in the study. A theoretical maximum of about 20 % reduction in reserve power and balancing energy was found for the case of completely uncorrelated load forecast errors. It was pointed out, that the pooling would require additional organizational effort and would induce an additional grid load.

The short and medium-term potential of demand side management for the provision of balancing power was also discussed in the study. Large industrial electricity consumers are able to participate in the balancing power market. This is already done and the future development will depend on the expected revenue, i.e. on the prices for reserve power and balancing energy. An additional potential of reserve power could be made available from household customers, if a communication system is developed, which allows to control the domestic appliances. It was estimated that the control of fridges and freezers has a potential of maximum 3 GW positive and negative balancing power. If washing machines tumble dryers and dishwashers are included, the potential would increase to 7 GW during daytime. This however, would require a clear change in user behaviour.

The balancing power requirement in a system with high share of wind power, as investigated in the study, is dominated by the deviations of wind power generation from its forecast. The use of generation management of wind power allows to significantly reduce the wind induced additional positive reserve power need. From the system point of view it is most efficient to reduce wind power generation in cases where the available reserve power is at its limit. In this way the maximum balancing power need is limited. In an example calculation it is shown that a reduction of the wind induced additional balancing power need by 70 % leads to a loss of power production of less than 0.2 %. A rough cost estimation shows that this is also economically sensible in a large scale.

The potential of compressed air energy storage (CAES) to balance the fluctuating power output of wind power has also been investigated. Three different management strategies have been compared for an example CAES with 400 MW generator and 250 MW compressor power, costing about 250 Million Euros (M€):

1. Electricity is bought at the spot market at low price hours, stored in CAES and sold at high price hours. This strategy is not feasible with current market prices.
2. The power plant is used as reserve power plant. A revenue of 10 M€ per year can be obtained with the currently very high prices for minute reserve in Germany.
3. The CAES plant is used to shift the weather dependent power output of wind power to times of high prices on the spot market. Additionally the free capacity of the CAES is used as reverse power plant. A revenue of 17 M€ per year would be feasible, if the CAES was paid for the avoided reserve power, which otherwise would be needed to cover the forecast error of wind power.

3.8 UK

In the United Kingdom, government policies aim to meet 15 % of the country's electricity needs from renewable sources (mainly wind power) by the year 2015. With the rapid growth of wind power in the UK the extent and cost of the provision of these additional operating reserves may become significant. In the last few years some studies have been carried out in the UK to comprehend the magnitude and cost of these additional system balancing requirements (Dale et al, 2003; MacDonald, 2003; UKERC, 2006). Those studies considered more relevant to this report are described in this section: (Ilex/Strbac, 2002) and (Strbac et al., 2007).

3.8.1 Ilex/Strbac, 2002

The scope of this study conducted for the UK Department of Trade and Industry, was to quantify the additional system costs that are likely to be incurred if the volumes of renewables in Great Britain are to increase to 20 % or 30 % of demand by 2020. The study used scenario analysis to estimate the costs under various combinations of demand, renewable technology mix and volumes of renewable (predominantly wind) generation. The wind did not make the same portion of the renewables penetration in the study, although in many cases wind was most (about 95 %) of the renewables.

Results: Balancing costs in this study comprise:

- Response and Synchronised reserve costs; related to the balancing of generation and demand over seconds and minutes.
- Standing reserve costs; related to the balancing of generation and demand over hours.
- Start-up costs.
- Wind curtailment costs; incurred usually during periods of low demand and high wind output, when wind generation needs to be constrained-off the system to avoid over-generation relative to demand.

The total balancing costs, prior to netting off the baselines, are illustrated in Fig 26. It can be observed that although response costs are the greatest component of total costs in the baselines, they are a far less significant element of the additional costs. In contrast, reserve costs are most substantial of the additional balancing costs.

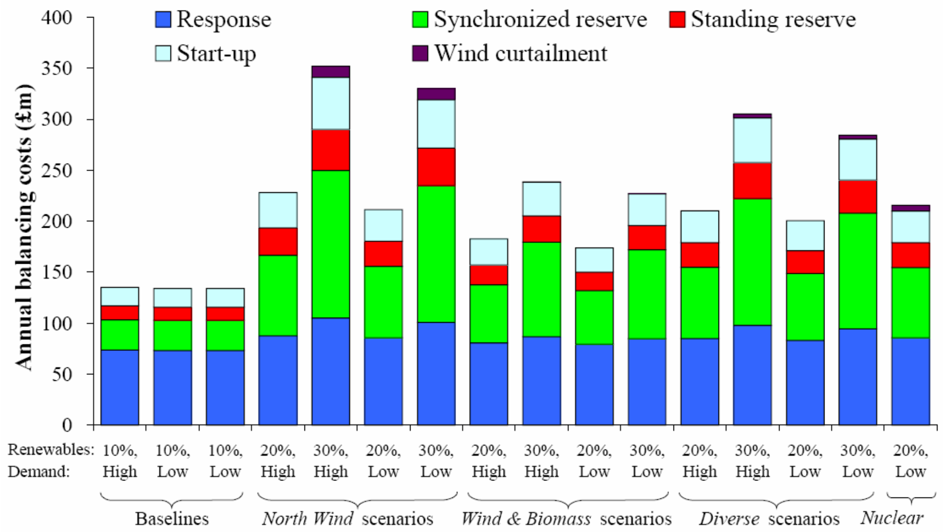


Fig 26. Total annual balancing cost by component. Wind represented most of the renewables in most of the cases.

Estimates of extra short term balancing or reserve costs were not explicitly made in the report. Taking the original values and dividing by produced wind energy resulted in £2.38 per MWh of wind produced for 10 % wind, rising to £2.65/MWh at 15 % and £2.85/MWh at 20 %. The costs were presented as additional, so on top of 10 % renewables case.

Input data, wind power modeling: Wind generation data used was gathered from 39 wind projects across UK with an averaging period of a half-hour over a consistent one year period. To build profiles of high wind penetration, representative of the diversity of the large scale wind generation, diversity was created by time-slipping proportions of aggregate half hourly wind profiles, to build up new profiles. Time-slipping involves scaling-up the observed generation data by overlaying annual half-hourly aggregate generation profiles for the 39 projects, but slipping each tranche of data by half-an-hour more than the last tranche. The sum of these profiles becomes representative of substantially large wind systems. The degree of diversity introduced was an arbitrary assumption, with our target level of diversity being a middle point between the observed diversity exhibited by the wind projects for which data was available and a theoretical maximum diversity if output across a much larger number of projects was totally uncorrelated.

Frequency distributions of the level of wind power variation in half-hr (relevant for determining response requirements and four-hour (relevant for determining reserve requirements) are shown in Fig 27.

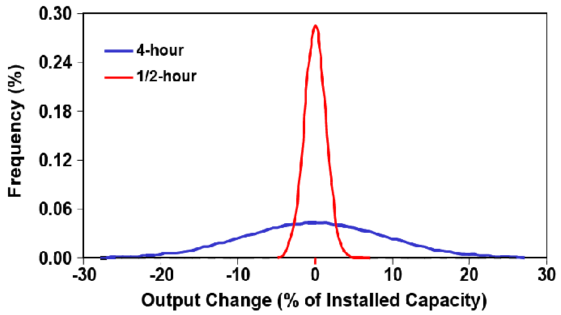


Fig 27. Frequency distribution of changes in wind generation over half-hour and four hour time horizons.

Methodology: In order to assess the additional resources to manage the balance between generation (both conventional and wind) and demand the standard deviations of fluctuations in renewable generation were statistically combined with the variations in demand and conventional generation to determine the amount of operating reserve (response and reserve) that would cover about 99 % of the mismatches between demand and supply in the characteristic time horizon.

Two approaches, simulation and analytical, were applied to assess the additional cost of system balancing that includes de-loading, holding, start-up, running and the cost of wind energy curtailment.

In the simulation approach, system operation is modelled by stepping through time series data and taking into account a number of dynamic constraints such as start-ups, minimum on and off times, ramp rates, minimum stable generation etc. A combined energy, response and reserve scheduling programme was applied for this purpose. The cost of balancing was estimated by performing a number of simulation studies on six characteristic days covering business and non-business days in all seasons. Annual costs were estimated by scaling up the sample days on a time weighted basis to represent a year. The analytical approach uses statistical analysis methods. A range of studies performed confirmed that both methods were giving acceptably consistent results. The analytical approach, being less complex and computationally less intensive was mainly applied with the simulation approach to calibrate the analytical model in order to run the sensitivity and cost assessments.

Assumptions: All generators operating in the system were assumed to contribute to system inertia. The amount of dynamic response that a conventional generator provides was considered to be at least 10 % of its installed capacity. Efficiency losses were considered to be between 10 % and 20 %.

Synchronised reserve was provided by part-loaded coal and CCGT plant while standing reserve was provided by OCGTs and pump storage plant. The allocation of reserve between Synchronised reserve and Standing plant was determined by a trade-off between efficiency losses of part-loaded synchronised plant (plant with relatively low marginal cost) and the cost of running standing plant with high marginal cost.

Limitations: The techniques applied for determining the need for operating reserve and associated costs does not comprehensively capture various impacts raised by variable and uncertain wind generation on power system operation such as the few analysed in the second study (Strbac et al.) described in this report.

3.8.2 Strbac et al., 2007

Impact of wind generation on the operation and development of the UK electricity systems (Strbac et al., 2007).

In order to deal with unpredicted variations in demand and generation, the system operator requires appropriate automatic response, to neutralise rapid variations from a few seconds to a few minutes, and reserves to deal with slow variations over time horizons from several minutes to several hours. On average, the UK system operator commits about 600MW of dynamic frequency control, while about 2400MW of various types of reserve is required to manage the uncertainty over time horizons of the order of 3–4 hours. These values could be significantly changed in the future with increase in wind penetration levels considering that wind generation is both variable and unpredictable. The reserve requirements are driven by the assumption that time horizons larger than 4 hours will be managed by starting up additional units, which should be within the dynamic capabilities of gas fired technologies.

Results: The additional response and reserve requirements due to wind generation and their associated costs are are depicted in table 11 for various levels of wind generation in the system. The increase in demand for continuous frequency regulation was found to be relatively small for modest increases in wind power connected. However, at high wind penetrations the reserve levels equivalent to 25 % of wind installed capacity will cover even the extreme variations in wind output.

Table 11. Additional requirements for continuous frequency response and reserve for increasing wind power penetration in UK. Expected minimum and maximum of MW reflect the dispersion of wind power plants. Expected minimum and maximum of costs reflect also the reserve holding cost range 2–4 £/MWh. Cost converted from consumer costs in (Strbac et al., 2007) to €/MWh wind energy assuming 1 £ = 1.3 €.

Installed wind capacity GW	Additional frequency response requirements MW		Range of additional cost of frequency response €/MWh		Additional reserve requirements MW		Range of additional cost of reserve €/MWh		Total additional cost of reserve €/MWh	
	Min	Max	Min	Max	Min	Max	Min	Max	Min	Max
5	34	54	0.1	0.3	340	526	0.7	1.7	0.8	2.0
10	126	192	0.3	0.6	1 172	1 716	1.4	2.5	1.6	3.1
15	257	382	0.4	0.8	2 241	3 163	1.7	3.1	2.1	3.8
20	413	596	0.5	0.9	3 414	4 706	1.9	3.5	2.3	4.4
25	585	827	0.5	1.0	4 640	6 300	2.0	3.7	2.6	4.7

The expected minimum figures correspond to a highly diversified wind output. If there will be large concentrations of wind power plants now expected in The Wash, Thames Estuary, North West England or Scotland, the need for continuous frequency response is likely to be closer to the expected maximum.

It was concluded that the amount of extra reserve can be handled with the current conventional power plants, so only the cost of operating reserves more has been estimated in Table 11.

This study has also quantified the value of storage in providing standing reserve by evaluating the difference in the performance of the system, fuel costs (and CO_2), when variability is managed via synchronized reserve only, against the performance of the system with storage facilities used to provide standing reserve. Considering different flexibility levels of generating capacity in the system, the capitalized value of the reduced fuel cost due to storage is as high as

970 £/kW for systems with low flexibility, and 252 £/kW for systems with high flexibility.

Input data, wind power modeling: This study used an updated wind input time series data from the previous (Ilex, 2002) study.

Methodology: The additional response and reserve requirement was estimated using 3 sigma of the distribution of load and wind+load variations. Persistence based technique is applied to determine the wind forecast errors across the given time horizons. Standard deviations of wind forecast error is combined with the standard deviations of demand/generation forecast errors to determine the level of the overall mismatch (error) that need to be managed. This is calculated following the standard statistical approach of combining the independent (uncorrelated) errors (the mean square error of the combination is the sum of the mean square errors).

For the evaluation of the cost of reserve two scenarios are investigated, with fuel cost of £10/MWh and £20/MWh. The cost is obtained by assuming that the cost of holding synchronised reserve will be, on average, between £2/MW/h and £4/MW/h, for fuel cost of £10/MWh and £20/MWh, respectively, given the assumptions of efficiency losses of about 20 % and that all wind power output can be absorbed by the system.

Assumptions: The cost is obtained by assuming that all wind power output can be absorbed by the system. For relatively high penetration of wind power (above 20 %) in systems with the conventional generation dominated by plant of low flexibility (such as nuclear), it may not be possible to absorb all wind power generated. However, in such a system, reserve provided by standing plant (OCGT or storage) will increase the capability of the system to incorporate wind power.

Limitations: It is important to mention that demand currently makes a significant contribution to providing non-dynamic response in UK and the role of demand could increase which would reduce the cost of both reserve and response. However, this was not included in this study.

3.9 Ireland

Investigations into the effects of integrating wind power into the Irish electricity system and the limits to wind energy penetration date from 1990. Many of the earlier studies on wind energy in the Irish power system looked solely at transmission network issues rather than effects upon the generating system.

3.9.1 Ireland/SEI

Sustainable Energy Ireland published a report "Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System" (Ilex et al., 2004).

Results: The study findings were that fuel cost and CO_2 savings up to a 1500MW wind power penetration in the ROI system were directly proportional to the wind energy penetration. It was found that over longer time horizons (1 to 4 hours), there is an increasing requirement for additional operating reserve as wind penetration increases, as shown in Table 12 below. It found that while wind did reduce overall system operation costs it could lead to a small increase in operating reserve costs 0.2 €/MWh for 1300 MW wind and 0.5 €/MWh for 1950 MW of wind.

Table 12. Additional reserve requirement for different levels of installed wind power.

Wind Power Installed (MW)	% Gross Demand	1 hour Reserve Requirement (MW)	4 hour Reserve Requirement (MW)
845	6.1	15	30
1 300	9.5	25	60
1 950	14.3	50	150

Input data, wind power modelling: time series generated from statistical manipulation of historic wind power plant data. 10 % of wind power is offshore, 50 % is onshore connected to transmission network, and 40 % is onshore connected to distribution network.

Methodology: The system assessment methodology was generating system simulation using a proprietary system dynamic model. The costs used for this were derived from a dispatch model. Review matrix is in Appendix 2.

Assumptions: It is assumed that it is possible to curtail wind production if necessary.

Limitations: Study looked at impact on operating reserve only, did not take into account transmission network. Limited quantity of high quality wind generation data. Study did not explicitly look at capacity issue.

3.9.2 Ireland / All Island Grid Study

In 2005 both governments on the island of Ireland (republic of Ireland and Northern Ireland) jointly commissioned the All Island Grid Study (All Island Grid Study, 2008). The purpose of the study was to investigate the impacts of various penetration levels of renewable energy on the island of Ireland in the year 2020. This comprehensive study began with development of six suitable portfolios and an extensive resource assessment. The technical core of the study consisted of a network study and a scheduling and dispatch study. The final part of the study was a full economic analysis. Here in this section the emphasis is on the results of scheduling and dispatch studies other parts of the study being described elsewhere in this report.

Results: The scheduling and dispatch study found that it was feasible to operate the all island power system reliably with up to 42 % energy from renewable resources, mainly wind. The cost difference between the portfolios was relatively small. Specifically Portfolio 1 had 2GW of wind and 16 % energy from renewable while Portfolio 5 had 6GW of wind and 42 % of energy from renewable and the cost difference was 7 %. Substantial CO_2 reductions were achieved with the higher wind penetrations both on the island of Ireland and Great Britain through two 500MW interconnectors. The study also found that additional storage and improvements in existing wind forecasting performance did not appear to give any additional benefits.

Input data, wind power modelling: one hour resolution time series generated from statistical manipulation of historic wind power plant data. With the exception of Portfolio 6 all wind power was on land.

Methodology: The study was carried out using the Wilmar planning tool that was specially adapted to the Irish system. In particular the Wilmar tool was run in a full mixed integer mode with two types of reserve modelled (operating and replacement) in a comprehensive manner, and load was treated stochastically. Wind power was curtailed in circumstances where it was deemed to be the most economic thing to do.

Assumptions: The study had many significant assumptions including fuel and carbon costs, and no network constraints were considered in this part of the study. A full network study was conducted in parallel.

Limitations: Due to computational burden there was a limited number of sensitivity runs. Wind data was based on one year historical data that had a favourable wind output at times of peak, consequentially the portfolios may need more capacity to make them adequate. Additional cycling and start-ups of thermal plant were significant with high wind penetrations and the potential additional costs were not accounted for. Intra hour operation of the power system was neglected in particular potential inertial response restrictions.

3.10 Netherlands

The commercially available unit commitment and economic despatch tool PowrSym3 is used for the simulation of wind power integration in an international environment. An existing generation unit database for the Netherlands is extended to include conventional generation portfolios of neighbouring areas to the Netherlands. Furthermore, wind power in Germany is modeled such that the spatial correllation between wind speeds at different locations in the Netherlands and Germany is maintained. These additions allow the assessment of the benefits of international exchange for wind power integration and a comparison with other integration solutions. The unit commitment and economic despatch tool is applied for annual simulations of a power system with generation portfolios foreseen for the year 2014. The simulations are performed for a range of wind power penetrations of 0–12 GW in the Netherlands (with 12 GW supplying approximately 33 % of Dutch annual consumption), market designs (isolated system – flexible use of interconnections) and wind power forecasts.

Technical limits to the system integration of wind power in the Dutch system have been identified and the economic and environmental impacts of wind power on system operation quantified. Furthermore, the opportunities of energy storage and heat boilers for the integration of wind power in the Dutch system have been explored. Pumped accumulation storage (PAC), underground PAC (UPAC), compressed air energy storage (CAES), the use of heat boilers at selected combined heat and power (CHP) locations and increased interconnection capacity with Norway (NN2) may provide additional technical space for wind power integration. The solutions are placed in an order of potential with respect to technical, economic and environmental aspects. The results show that the advantages of international exchange for wind power integration are large and provide an alternative for the development of energy storage facilities (Ummels, 2009).

Results:

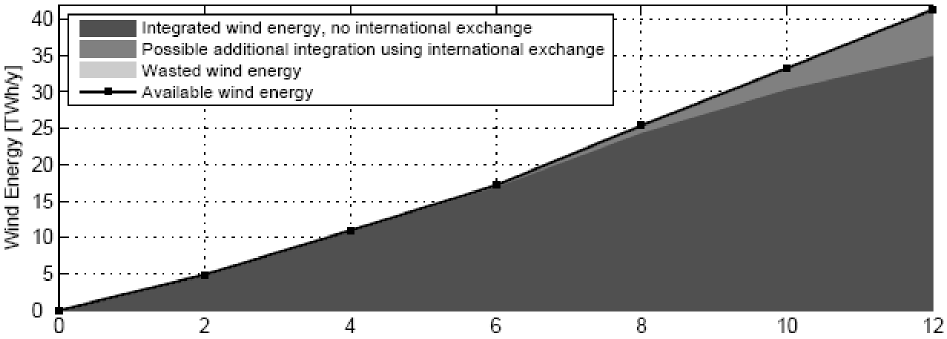


Fig 28. Integrated and wasted wind energy in the Netherlands.

The simulation results indicate that for the Dutch thermal generation system, ramp rate problems due to the aggregated variations of load and wind power are rare. This can be explained by the existing commitment constraints imposed on base-load coal units (must-run status) and combined heat and power units due to heat demand, resulting in a high operating reserve levels. The high reserve levels provide sufficient ramping capacity for balancing wind power variability in addition to existing load variations. For the optimization of system operation with large-scale wind power, it can be noted that accurate, actualisations of wind power output and a continuous re-calculation of unit commitment and economic despatch are essential.

Although the additional variations introduced by wind power can be integrated, and do not present a technical problem, limits for wind power integration increasingly occur during high wind and low load periods. Depending on the international market design, significant wind power opportunity may have to be wasted to prevent minimum load problems (Fig 28). Wind power integration benefits from postponed gate closure times of international markets, as international exchange may be optimised further when improved wind power predictions become available.

The simulation results show that wind power production reduces total system operating cost, mainly by saving fuel cost. Wind power reduces the number of full-load hours of base-load coal-fired generation, and to a lesser extent those of CCGT (with and without CHP-function). This has particular impacts on the profits of owners of these conventional generation units. By replacing fossil-fired generation, wind power significantly reduces the total exhaust of emissions (CO_2, SO_2, NO_X). In case possibilities for international exchange exist, wind power significantly reduces imports and increases exports of the area it is integrated into. In the case study performed here, it is shown that the presence of large-scale wind power in Germany limits the use of exports for wind power integration in the Netherlands during some periods. Still, international exchange is shown to be key for wind power integration, especially at high penetration levels. As such, possibilities for international exchange should be regarded as a promising alternative for the development of energy storage in the Netherlands itself.

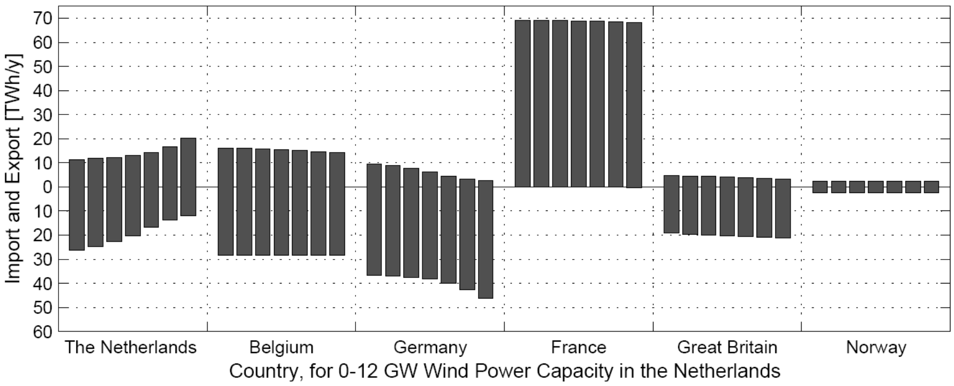


Fig 29. International exchange in North-West Europe for 0–12 GW wind power installed capacity in the Netherlands.

In case international exchange is possible, the integration of wind power in the Netherlands influences in principle the exchanges between all countries. In Fig 29, imports and exports are shown for each country with each bar representing a wind power penetration scenario. Clearly, the Netherlands increases its annual exports and decreases its imports in case more wind power is installed. This influences mainly imports and exports of Germany and Great Britain, and Belgium to a limited extent.

Large interconnection capacities are present between Germany and the Netherlands and Dutch wind power mainly decrease the full-load hours for base-load coal and lignite in Germany, but also some CCGT. Wind power furthermore reduces the exports of base-load coal power from Belgium and to a lesser extent from France during periods of low load (nights and weekends). Germany reduces its imports from France at times of high wind in the

Netherlands. Exchanges with Norway stay constant in volume since it is modeled as such, although the moments of exports and imports are increasingly determined by wind power as its installed capacity in the Netherlands increases. These results clearly show the importance of the larger, Germany system for the integration of wind power in the Dutch system.

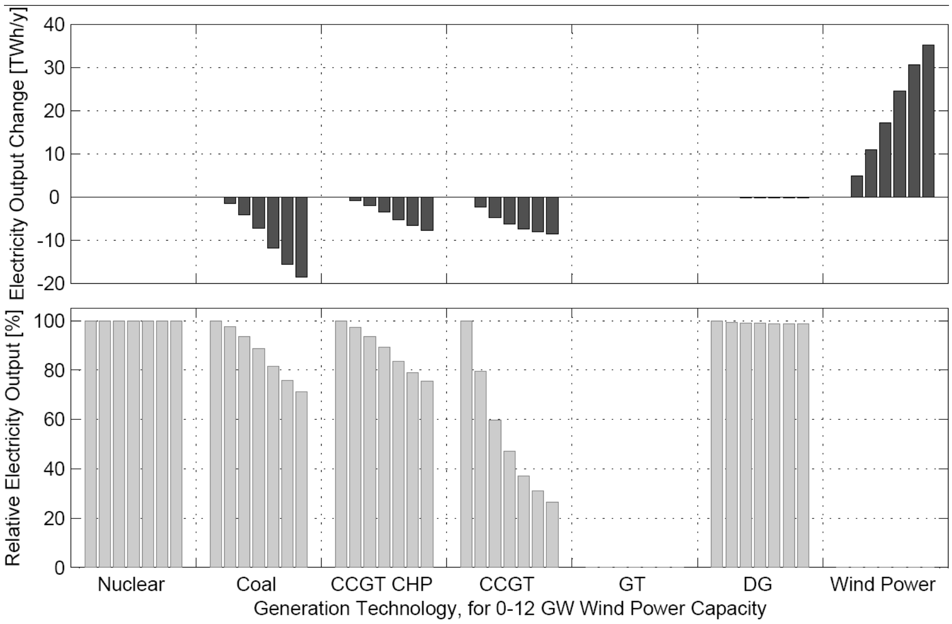


Fig 30. Absolute electricity production change and relative output per technology in the Netherlands for different wind power penetration scenarios, no international exchange.

In Fig 30, the change in annual electricity output between different generation technologies is shown for the Netherlands (no international exchange) with increasing wind power capacity. Nuclear, being a full-load must-run technology, is not affected by wind power integration. Wind power does reduce the full-load hour equivalents of coal-fired units, CCGT CHP and CCGT. Importantly, the profits of these units also decrease during the hours that they are in operation, since wind power always replaces the most expensive unit in operation (as far as technically feasible). Because of the large share of coal-fired generation in the Dutch generation park modeled in this research, the electricity generation [TWh/y] of coal is reduced most.

Notably, the technical flexibility of coal, CCGT CHP and CCGT does not require additional operating hours of peak-load gas turbines for wind power integration. DG (greenhouse gas engines) decreases its operation hours only very slightly: the must-run part is fixed, and the flexible units produce heat and power during other periods, with the heat being stored. On a relative scale, the output of CCGT is affected most by the integration of wind power: CCGT operates only during medium- and peak-load hours, during which it is often the marginal technology and therefore the first to be replaced by wind power. Since coal and CCGT CHP have a part-load must-run status, the integration of wind power reduces their output only to a certain extent.

Methodology: The unit commitment and economic despatch tool used in this thesis is PowrSym3TM, developed from the 1980s onwards by Operation Simulation Associates, Inc. and the former Dutch utility SEP with support from the Tennessee Valley Authority. PowrSym3 is a multi-area, multi-fuel, chronological generation cost simulation model for electrical power systems including combined heat and power, energy storage and energy limited fuel contracts. PowrSym3 is a rolling unit commitment and economic despatch optimisation tool, i.e. unit commitment and economic despatch are updated every simulation state based on best available load and wind power forecast, while taking into account technical constraints following from previous states. The tool allows different simulation time-steps and 15 min. time-step was applied in this research PowrSym3 applies heuristics, or computer intelligence based on operational experience, for an initial optimisation of the unit commitment and economic despatch. The solution obtained from the heuristics is used as an input for a so-called ‘smart’ dynamic programming algorithm for further optimisation of the unit commitment.

Assumptions: Perfect market assumption i.e. power producers will produce when prices become higher than short-term marginal production costs (mainly fuel costs), and there will be no exercise of market power. International exchange is scheduled as part of the UC–ED such that all feasible transactions are made, under the assumption that the future wind power output is equal to the best wind power forecast available at gate closure. No possibilities for reservation of transmission capacity by specific market actors before the daily operation takes place. All production capacity is available for the balancing of wind power production except the capacity restricted by start-up times or other technical constraints. This corresponds to assuming a very liquid regulating power market. It is assumed that a wind power forecast update is available each hour and that the actual wind power level is exactly known.

Limitations: Only one wind power forecast was available for the Netherlands and for Germany. Unit commitment and economic despatch are optimised based on the best available wind power forecast and the actual wind power output.

3.11 USA

3.11.1 Minnesota 2004

The Minnesota Dept. of Commerce/Enernex Study was completed in 2004 (EnerNex/WindLogics, 2004). It estimated the impact of wind in a 2010 scenario of 1500 MW of wind in a 10 GW peak load system.

Results: Hourly to daily wind variation and forecasting error impacts are the largest cost items. Incremental regulation due to wind was found to be 8 MW (at 3σ confidence level). Incremental intra-hour load following burden increased 1–2 MW/min. (negligible cost).A total integration cost of $4.60/MWh was found, with $0.23/MWh representing increased regulation costs, and $4.37 due to increased costs in the unit commitment time frame. Balancing energy was self-provided by reserves carried by the control area operator.

Input data, wind power modeling: Three year data sets of 10-minute power profiles from atmospheric modeling were used to capture geographic diversity. Wind plant output forecasting was incorporated into the next day schedule for unit commitment. Extensive time-synchronized historic utility load and generator data was available.

Methodology: Review matrix is in Appendix 2 (Table A5).

Assumptions: A monopoly market structure, with no operating practice modification or change in conventional generation expansion plan, was assumed.

Limitations: No control area consolidation or market operation was assumed in this study.

3.11.2 Minnesota 2006

An update to the MN Dept of Commerce study was completed in 2006 by the same EnerNex/WindLogics team performing the 2004 study. This study looked at the integration cost associated with providing 25 % energy from wind to the load in the state of Minnesota, assuming a well-developed market operating in the territory of MISO, the Midwest Independent System Operator.

Results: The study results show that the addition of wind generation to supply 25 % of Minnesota load can be reliably accomodated by the power system, if adequate transmission is provided to support it. The highest wind integration cost was found to be $4.40/MWh of delivered wind energy, including the cost of additional reserves. The control area consolidation in Minnesota, and the size of the MISO market made a significant difference in the results, compared to the 2004 study. Balancing energy within the hour is provided by resources within the Minnesota balancing area at marginal cost. Hourly variations are managed at the MISO market level.

Input data, wind power modelling: Three year data sets of 5-minute wind plant output power profiles from atmospheric modeling were used across a region consisting of a square approximately 750 km on a side to model 6,000 MW of wind capacity, achieving a good geographic diversity. Wind plant output forecasting was incorporated into the next day schedule for unit commitment, and into next hour scheduling for real-time operation. Extensive time-synchronized historic utility load and generator data was available.

Methodology: Review matrix is in Appendix 2.

Assumptions: A well-functioning market region, consisting of day-ahead, hour-ahead, and ancillary service markets, has evolved in MISO, virtual control area consolidation has occurred for the state of Minnesota, and transmission congestion has been eliminated for all practical purposes.

Limitations: The MISO territory covers parts of 14 states, with a current market load of 116 GW. The next round of studies should examine the extension of the RPS to additional parts of MISO outside of the assumed Minnesota load of 21 GW.

3.11.3 New York

The study for the New York ISO (GE Energy, 2005) estimated the impact of wind in a 2008 scenario of 3300 MW of wind in 33-GW peak load system. Wind power profiles from atmospheric modeling were used to capture statewide diversity. The study used the competitive market structure of the NYISO for ancillary services, which allows determination of generator and consumer payment impacts. For transmission, only limited delivery issues were found. Post-fault grid stability improved with modern turbines using doubly-fed induction generators with vector controls. Incremental regulation due to wind was found to be 36 MW. No additional spinning reserve was needed.

Incremental intra-hour load following burden increased 1–2 MW/ 5 min. Hourly ramp increased from 858 MW to 910 MW. All increased needs can be met by existing NY resources and market processes. Capacity credit was 10 % average onshore and 36 % offshore. Significant system cost savings of \$335–\$455 million for assumed 2008 natural gas prices of \$6.50–\$6.80/MMBTU were found. The results for improved forecasting were also studied. Day-ahead unit-commitment forecast error σ increased from 700–800 MW to 859–950 MW. Total system variable cost savings increases from \$335 million to \$430 million when state of the art forecasting is considered in unit commitment (\$10.70/MWh of wind). Perfect forecasting increases savings an additional \$25 million.

3.11.4 Colorado

The Xcel Colorado/Enernex Study (2006) (Zavadil, 2006) examined 10 % and 15 % penetration cases (wind nominal to peak load) in detail for ~7 GW peak load system. (The results for 20 % penetration case where not available in time of printing of this report.) Regulation impact was \$0.20/MWh and hourly analysis gave a cost range of \$2.20-\$3.30/MWh. This study also examined the impact of variability and uncertainty on the dispatch of the gas system, which supplies fuel to more than 50 % of the system capacity. Additional costs of \$1.25–\$1.45/MWh were found for the 10 % and 15 % cases, bring the total integration costs to the \$3.70–\$5.00/MWh range for the 10 % and 15 % penetration cases.

3.11.5 California

The CA RPS Integration Cost Project examined impacts of existing installed renewables (wind 4 % on a capacity basis). Regulation cost for wind was \$0.46/MWh. Load following had minimal impact (Shiu et al., 2006).

The California Energy Commission (CEC) funded the California Intermittency Analysis Project (IAP) which was completed in 2007 (Porter et al., July 2007). Using the tools of transmission load flows, statistical analysis, and production cost modeling, the study examined the impacts of higher levels of renewable energy in response to meeting the Renewables Portfolio Standard of 20 % renewable energy by 2010 and the accelerated target of 33 % renewable energy by 2020 (which is about 15 % energy from variable renewable wind and solar). They find that the integration issues can be managed with some reasonable changes in transmission infrastructure, operations and policy, with some operating challenges expected in some extreme condition hours with light loads and high wind and hydro output conditions. The results and recommendations based on the statewide analysis provide a framework for system operators, utilities, and infrastructure planners to gauge transmission and future grid needs for the region as more renewable energy generation is installed in California.

The report findings were divided into Generation Resource Adequacy, Transmission Infrastructure, and Renewable Generation Technology, Policy and Practice. Among the resource adequacy findings, some of the more important were:

- Pursuing generating resources with greater minimum turn-down and diurnal start/stop capabilities, ensuring greater participation by loads, and optimizing use of pumped storage hydro will aid with integrating variable renewable energy generation.
- California should consider allowing import and export scheduling to occur more frequently and at other times than on the hour.
- The effect of variable renewables on regulation is relatively modest. The variability across all time frames increases by 7–8 %, with 3 sigma values of changes in the 1 hour, 5 minute (load following), and 1 minute (regulation) time periods respectively of 387 MW, 42 MW, and 10 MW. The 3 sigma values of the hourly time changes for the lowest 10 % load hours are much higher, about 1041 MW, and increase to 60 MW for the 5 min load following period. The 1 min value shows no significant change. The corresponding CAISO peak load is 66,700 MW, and the wind and solar capacity are 12,700 MW and 6,000 MW respectively.
- While operational flexibility is valuable to the grid, it can impose significant costs and revenue reductions on generation providers. Expanded ancillary service markets, incentives, and requirements may be necessary to overcome this problem.

Upon completion of the CEC report, the California Independent System Operator (CAISO) undertook some additional analysis based on the results of the CEC IAP (Loutan et al., November 2007). Operational impacts were found to be similar, with the exception of the regulation requirements. The CAISO determined that its regulation capacity requirements will increase by 170 MW to 250 MW for “Up Regulation” and 100 MW to 500 MW for “Down Regulation” (400 MW corresponds to about 5 % of installed wind power capacity). The amount of increase varies with the season and hour. This regulation requirement is 10 times larger than that found in the CEC study performed by GE, and is claimed to be due to a detailed model that more accurately represents the time lags in the Automated Dispatch System and in generator response to dispatch commands. No further analysis of this claim has been made.

3.11.6 PacifiCorp

PacifiCorp is a regulated electricity company operating in portions of the states of Utah, Oregon, Wyoming, Washington, Idaho and California, serving a peak load of 9,000 MW in 2004. As a vertically integrated electric utility, PacifiCorp owns or controls fuel sources such as coal and natural gas. Along with sources of wind, geothermal and hydroelectric resources, as well as energy from the wholesale market, PacifiCorp serves its customers throughout its six-state region.

An Integrated Resource Plan (IRP) is developed by PacifiCorp every two or three years. The IRP provides an analytical framework for PacifiCorp to investigate the costs and risks associated with a range of future possibilities to serve the load in its six-state-region. This framework provides a useful basis for discussion of the least cost plan with the regulatory bodies which oversee its operation. It provides a robust analytical framework to simulate the integration of new resource alternatives with PacifiCorp’s existing generation and transmission assets. The hourly dispatch model used for the analysis includes consideration of market trading hubs, and transmission paths and constraints, to provide a detailed examination of the economic and operational performance of resource alternatives.

PacifiCorp first introduced wind into its IRP in 2003 (Dragoon & Milligan, 2003). At a penetration level of 1,000 MW, the cost of incremental operating reserves in the 2003 IRP for a wind site with a capacity factor of 30 % was \$2.72/MWh. Combined with the \$3.00/MWh estimate for imbalance, the total integration cost for 1,000 MW was approximately \$5.50/MWh. Since this analysis was first completed, the assumption for imbalance costs have remained unchanged at \$3.00/MWh in 2002 dollars but the cost of incremental reserves has been updated for new market prices. The same methodology was used in the update, only the cost of reserves was adjusted. Currently for 1,000 MW of wind capacity in the system, the 20 year levelized cost of integration in 2004 dollars is estimated to be $4.64/MWh (PacifiCorp, 2005).

3.11.7 Texas

The Electric Reliability Council of Texas is an independent system operator that operates over most of the state of Texas. ERCOT looked at a study (GE Energy, 2007 ERCOT report) of wind penetrations up to 15,000 MW of wind power in a 65-GW peak load system. The main focus of this study was to evaluate the incremental requirements and costs on ancillary services with the higher penetrations of wind power. Using a 98.8th percentile for changes in regulation requirements with wind, the study reported about a 54 MW and 48 MW increase in up-regulation and down-regulation, respectively. The load following time-scale was not studied in detail and even though the responsive-reserve service was discussed the system reliability study that would be needed to assess the requirements for this service was beyond the scope of the study.

Interestingly in this study, the cost of regulation per MWh of wind using a state-of-the-art wind forecast increases as wind capacity reaches 10,000 MW up to $0.27/MWh, but then decreases to an actual savings of regulation costs at the 15,000 MW penetration level of $0.18/MWh. The reason for this is that even with the higher regulation requirements, the regulation clearing prices for the ancillary service market decrease as the unit commitment problem is solving to commit cheaper units because of the added wind capacity. Therefore, the lost opportunity costs for regulation decrease, as do the costs for regulation as the $/MWh regulation prices decrease. In reality, the incremental costs are somewhat volatile and can depend directly on the forecast accuracy. Whether the additional regulation cost is positive or negative the per-MWh values are too small to be of any significance. Wind generation also decreases the total energy cost on the system, the avoided cost of wind power was estimated to about $55/MWh of wind energy.

4. Grid reinforcement and efficiency

Requirements for new generation connecting to the network (Grid codes) assure that reliability of the grid will be maintained at a high level. Wind power affects grid adequacy and efficiency in several ways and time-scales. Some impact is negative, eg. costly or challenging from a technical point of view, but increasing wind power also brings along clear benefits and opportunities for the grid and the operation of it.

Large scale integration of wind power sets requirements for the power system, but also the wind power technology must be developed to meet system needs. The development of IEC 61400-21 (IEC, 2001) specifying procedures for characterizing the power quality of wind turbines and the various grid codes setting system requirements for wind power plants are examples of such development. In IEA WIND, previous Task 21 identified the need for validated dynamic models for wind power plants for power system studies (Tande et al, 2004). The different aspects of grid impact that wind power causes or contributes to are described below:

A. Voltage control – reactive power compensation

A main challenge related to voltage control is to maintain acceptable steady-state voltage levels and voltage profiles in all operating conditions, ranging from minimum load and maximum wind power production to maximum load and zero wind power. Modern wind turbines are equipped with power electronics which control reactive power output and terminal voltage within some range. After the generators themselves, capacitor banks and transformer tap changers represent the most common means to control voltage profiles. Static Var Compensators (SVC) and STATCOMs placed in the grid or at wind power plants open up possibilities to serve both the grid and wind power plants to the benefit of both. Another challenge in this context is related to the control (or limitation) of the exchange of reactive power between the main transmission grid and the regional distribution grid.

B. Voltage stability

Due to disturbances in the grid reactive power shortage at the wind power plant may occur. If the power system cannot supply adequate reactive power, a voltage instability or collapse may occur. Sufficient and fast control of reactive compensation with possible active power reserves is required to relax possible voltage stability constraints. This can be provided through the use of wind turbines with active voltage control, or by using external compensators (SVCs and STATCOMs).

C. Transient and dynamic stability

Before, the protection systems of wind turbines were designed to disconnect and stop the units whenever a grid fault (temporary or permanent) is detected. System requirements implying that wind turbines must be able to "ride through" temporary faults, and contribute to the provision of important system services, such as momentary reserves and voltage support, become more common with increasing wind power. This puts emphasis on transient stability performance, power oscillations and system damping. Also, the inertia of the power system is decreased when the share of wind power is increased. This is due to less synchronous generators being directly coupled to the grid. Consequently a power plant trip-off causes a larger and more rapid frequency drop.

Modern wind turbines can control both active and reactive power, in some cases more quickly than conventional power plants. Therefore the ability of wind turbines to actively support the power system during grid disturbances is now explored. Some simulation results indicate that with new equipment designs and proper plant engineering, system stability in response to a major plant or line outage can actually be improved by the addition of wind generation (GE Energy, 2005).

D. Transmission capacity and efficiency

The impact of wind power on the power transmission depends on the location of wind power plants relative to the load, and the correlation between wind power production and load consumption. Wind power, like any load or generation, affects the power flow in the network and may even change the power flow direction in parts of the network. The changes in use of the power lines can bring about power losses or benefits. Increasing wind power production can affect bottleneck situations. Depending on its location wind power may at its best reduce bottlenecks, but at another location result in more frequent bottlenecks.

Transmission capacity problems associated with wind power integration may typically be of concern for only a small fraction of the total operating time. Network investments can be avoided or postponed by several means. Applying control systems that limit the wind power generation during critical hours is one possible solution. Alternatively, if other controllable power plants are available within the congested area, coordinated automatic generation control (AGC) may be applied. Demand side management that is controlled according to the wind and transmission situation is another option. The latter two may be more beneficial than limitation of wind power as energy dissipation is avoided. Despite application of wind generation controllability and DSM, grid expansion and/or capacity reinforcement may become necessary not only in cases of very high wind penetration but also when it is necessary to extend the grid to areas to collect important and proved wind resources.

E. Adverse impact from interaction of power electronic converters

Modern wind turbines utilizing power electronic converters provide enhanced performance and controllability compared to traditional fixed speed solutions. With increasing use of power electronics, however, there may be uncertainties with respect to possible adverse control interactions within the wind power plant itself. Converter modulation principles and filter design are important issues that must be addressed and analyzed as part of the wind power plant design and installation.

4.1 Germany

4.1.1 Dena study

The results of the Dena grid study I show that the Federal Government’s goal of a share of at least 20 percent of renewable energy in power generation in Germany between 2015 and 2020 is achievable. However, the precondition for this is the implementation of the measures shown in the study in regard to the onward development of the power supply system.

Impact on grid reinforcement: In windy periods, network bottlenecks can be expected already for the 2007 time horizon unless new lines are constructed (Table 13). These bottlenecks will require intervention in the market in order to maintain system security. In total up to the time horizon 2015, there will be a need for approximately 850 km of 380-kV-transmission routes to transport wind power to the load centres. This corresponds to a share of 5 % of the currently existing extra high voltage line tracks. Reinforcement of 390 km of existing power lines will also be needed. In addition, numerous 380-kV-installations will need to be fitted with new components for active power flow control (e. g. Quadrature Regulators) and reactive power compensation (approximately 7,350 Mvar till 2015). The total costs for the transmission system extension necessary up to the time horizon 2015 are approximately 1.1 billion €.

Table 13. Grid reinforcement to integrate 36 GW wind power by 2015 (Dena, 2005).

Total wind power capacity	36 000 MW
Construction of new 380 kV lines	850 km
System reinforcement of existing lines	400 km
Qadrature regulators (1.400 MW in each case)	3
Reactive power compensation	7 350 Mvar

An increase in the use of renewable energies to generate electricity and developments due to the liberalisation of the energy markets result change the structure of electricity generation, which in turn affects the dynamic stability of the electricity grid (performance of the grid at times of fault-based fluctuations in voltage or frequency). The Dena Grid Study examined these effects, identifying critical situations and suggesting solutions.

Dynamic grid analyses have shown that certain faults can lead to large-scale voltage drops and critical grid situations. If, for example, a regional voltage drop of more than 20 % were to occur as a result of the three-pole short-circuit of a busbar, those wind turbines which were taken into operation before 2004 would have to disconnect from the grid in accordance with the Grid Codes in force at that time. These additional disconnections would worsen the critical grid situation and could lead to a total short-term drop of over 3,000 MW due to a voltage drop. This value exceeds the primary control reserve level maintained by UCTE (Union for the Coordination of Transmission of Electricity) to compensate for short-term power station failure and could thus put the reliability of supply in the German and European interconnected network at risk. To prevent this, the regulations were altered for power stations joining the grid from 2004 on. According to the new terms, wind power plants should not disconnect from the grid until the voltage drops by more than 80 %.

Wind turbines installed before 2004 are, however, still ruled by the old grid regulations, thereby endangering dynamic grid stability and as such increasing the supply risk. In principle, technical instruments are available for the adaptation of the interconnected network and power stations, but their implementation still needs to be examined in detail and agreed between network and wind power plant operators. The measures include:

- technical adaptation of old wind turbines built before 2004 to the standards of the new Grid Codes
- installation of voltage-supporting devices such as static var compensators
- accelerated repowering and
- further enhancement of the Grid Codes.

Based on the results of the Dena study and other studies and on the experience with existing wind projects, modification of the existing Grid Code for connection and operation of wind power plants in the high voltage grid will be necessary, for instance in view of fault-ride-through and maintaining grid voltage relative to voltage control. E.ON Netz has adapted its Grid Code for the high and extra-high voltage system in April 2006 (http://www.eon-netz.com) on the one side, for a better adaptation of grid requirements to wind turbine capabilities and, on the other side, for the introduction of more specific control and protection rules. The implementation of the new and extended measures will e.g. improve and stabilize wind turbines behaviour and result in decreasing loss of wind power following disturbances (Erlich et al., 2006).

Input data, wind power modeling: Data on the regional development of wind energy for the years 2007, 2010 and 2015 is shown in Table 14. To describe the regional effects, the German extra high voltage grid is divided into six grid regions: East, Northwest, Central, Southeast, West and Southwest.

Table 14. Resulting feed-in wind turbine capacity per time horizon and grid region [in MW] (taking into account the coincidence factor of 0.9) (Dena, 2005).

	2003	2007	2010	2015
East	4 950	7 970	8 843	9 410*)
Northwest	4 240	4 980	5 250	5 600**)
Central	1 590	2 020	2 160	2 178
Southeast	70	200	280	298
West	1 620	4 052	4 946	5 647
Southwest	193	368	436	450
Total	12 663	19 590	21 915	23 583

*) additional offshore 2015: 1 540 MW

**) additional offshore 2015: 7 281 MW

For the static investigations the following situations are examined respectively for each examined time horizon:

- peak load without wind
- peak load with wind
- low load without wind
- low load with wind.

A comparison of generation, grid load, losses, storage and power exchange in Germany in 2015 for peak load with wind / without wind and low load with wind / without wind is shown in Fig 31. During times of low load and high wind up to 60 % of load is generated by wind energy only.

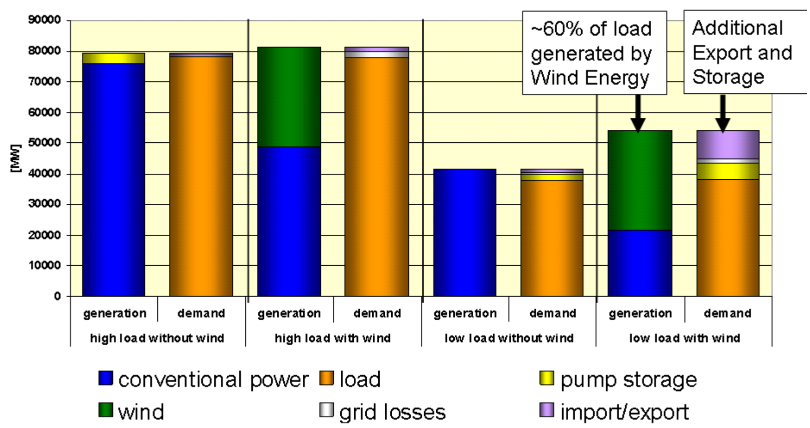


Fig 31. Comparisons of Generation, Grid Load, Losses, Storage and Power Exchange in Germany in 2015 (Dena Grid Study, 2005).

Methodology: The grid calculation software INTEGRAL developed by the research institute Forschungsgemeinschaft für Elektrische Anlagen und Stromwirtschaft e.V. (FGH e.V.) is used for quasi-static calculations. The dynamic calculations and simulations carried out as a part of this study are carried out with the software NETOMAC.

Assumptions: For the calculations in the strong wind scenarios it is assumed that 90 % at most of the installed capacity from wind turbines are simultaneously fed into the grid throughout Germany.

Limitations: Analysis covers only the grid extension and effects in the 380 kV transmission grid.

4.1.2 Studies after Dena Grid Study

One of the aspects of the Dena Grid Study tackled in the new German EEG 2009 is the improvement of the behavior of wind turbines in the grid. The payment of the power production will depend on the compliance with technical requirements to the grid integration and the behavior of the turbines in the case of a grid fault. A study has been performed to support the BMU in the legislative provision (Bömer & Burges, 2008). Its aim was to develop the technical requirements for the legal provision and to estimate the additional cost for the turbines. Also a proposal for the proof of compliance has been developed based on type certificates and grid calculations.

The German Federal Ministry for the Environment, Nature Conservation and Nuclear Safety (BMU) also commissioned a study to investigate the optimization potential for the integration of wind energy into the German electricity grid (FGE/FGH/ISET, 2007). A number of approaches have been investigated with respect to their potential to improve the integration of wind power into the electricity supply system. The aim was not to quantify the effect of the different approaches, but to identify relevant and promising solutions. The investigations are based on the wind power scenario of the year 2020 of the Dena Grid Study.

- With regards to power balancing the study concludes that negative minute reserve is the only contribution of wind power to balancing the power in the grid, which is feasible with the current market organisation and economic framework in Germany. While technically wind power plants could also provide primary and secondary control power, they can not match the current prequalification and tender rules. Additionally, positive reserve power would require a permanent power reduction, which is not sensible from the CO_2 reduction point of view.

- With regards to the behaviour of wind turbines in case of a grid fault the study concludes that a passive fault ride through capability will not be sufficient in the future. In addition, the turbines have to be able to provide reactive power to the grid. An estimation of the additional cost of the turbines has not been made.
- Due to the difficulty to obtain building permission for overhead lines, the possibility of using underground cables for high and extra high voltage is much discussed in Germany. The study also investigated of the technical possibility and economic viability of cables instead of overhead lines at the different voltage levels including electrical losses. Technically, there is no general obstacle against the use of cables instead of overhead lines. However, some potential problems have to be addressed: The availability of cables and HVDC systems is lower than for cables, cables and GIL have an influence on the load flow distribution in a meshed grid and there is little operational experience with long cables. Economically, it is important to include the cost of energy losses, which are higher for overhead lines compared to cables. For 380 kV connections, the construction cost of cables is estimated to be a factor of 3 to 10 higher than that of overhead lines. Due to the higher losses in overhead lines, the factor in actual total cost is only 1,1 to 5,3. For 110 kV connections, a factor of 0,6 to 1,4 is calculated, i.e. cables are not generally more expensive than overhead lines. GIL and HVDC is generally much more expensive than AC cables.
- The study also investigates the potential of a temporary loading and dynamic rating of overhead lines to increase their transmission capacity. Temporary loading means to adjust the rating of the lines according to the maximum temperatures for each month. An increase of the line rating of up to 20 % in the winter months is estimated in an example. Dynamic rating models the transmission capacity online by using online measurements of several parameters like temperature and wind speed. In a demonstration project by E.ON an increase of up to 50 % could be achieved.

Lange and Focken (2008) investigated the increase of transmission capacity of 5 overhead lines due to temperature and wind speed dependence from the North to the middle of Germany in dependence of the total German wind power production at the same time. They conclude that the average transport capacity is increased by 40 to 90 % at times when the German wind power generation is above 75 % of the installed capacity. In 99 % of the time the increase is above 15 % for all lines, except some very unfavourable cases, where only an increase of 5 % has been calculated.

4.2 UK

The location of wind generation, like conventional generation, can have a significant effect on transmission. Historically, transmission costs in the UK have been driven by a north-south flow from thermal generators located predominantly in the north, to demand in the south. With significant wind resources in Scotland and off the North West and North East of England and North Wales coasts, it is possible to envisage scenarios where this pattern of flows endures, despite the retirement of many of the existing conventional stations, thereby increasing the requirement for transmission reinforcement and the level of transmission losses.

Alternatively, if onshore wind generation were developed across Great Britain and included the offshore wind resources around the England and Wales coast, then transmission reinforcement costs could be significantly smaller. Furthermore, the location of new conventional generation and of decommissioned plant will also have a considerable impact on the future needs for transmission capacity.

The effects of connecting wind power plants at various locations across the country on the transmission reinforcement cost was considered (Strbac et al., 2007). This included the impact of the locations of new conventional plant and decommissioning of existing generation. The range of cost was found to be between £65/kW to £125/kW of wind generation capacity for 26 GW of wind power and £35/kW–£77/kW for 8 GW of wind. Lower values correspond to scenarios with dispersed wind generation connections, with significant proportions of offshore wind around the England and Wales coast, while the higher values correspond to the scenarios with considerable amount of wind being installed in Scotland and North of England. Still higher costs could be obtained if all existing conventional generation is assumed to remain in service in Scotland and northern areas. A value of £100/kW is used as a representative value for transmission infrastructure costs. For 26 GW of wind, this implies capital investment requirements of £2.6b, but given the range of costs in (Ilex & Strbac, 2002), the investment, depending on its location, will be between £1.7b and £3.3b.

The cost of connecting dispersed wind generators in remote areas to the main transmission network may be significant. For example, the cost of connecting renewable resource from the Western Isles in Scotland or connecting offshore wind power plants to the transmission system may be considerable. Average wind connection costs are assumed to be in the range of £40/kW to £70/kW reflecting a variety of siting and different scope for economies of scale. £50/kW is used as a representative value. Assuming 60 % of wind is directly connected to the transmission system gives a connection capital investment requirement between £0.6b and £1b.

4.2.1 Impact on system stability

Much speculation exists concerning the influence of wind power plants on system operation and stability. Wind power plants based on Fixed Speed Induction Generators (FSIGs) have poor transient stability characteristics, but they add significantly to the damping of the system. The operating characteristic of a synchronous generator is such that power output changes are most directly linked to changes in rotor angle. Since, damping is governed by torque (or power) variations in phase with speed variations; the natural response of a generator connected to a power network is oscillatory. The operating characteristic of an induction machine is such that torque changes are related directly to speed changes. With an induction generator, therefore, under oscillatory system conditions the torque variations produced are predominantly in phase with speed variations. Consequently, under oscillatory conditions the power variation imposed on the synchronous generators is predominantly damping power so that the introduction of an FSIG on a system improves the system damping. Although damping contribution of a doubly fed induction generator (DFIG) tends to be less than that of a FSIG, the results indicate that significant improvement in the system damping and dynamic stability margin is provided.

4.2.2 Value of fault ride through capability for wind power plants

UK Centre for DG&SEE has conducted a study with the objective to estimate the order of magnitude of additional system cost that would need to be incurred in order to accommodate wind generation of varying degree of the capability to withstand faults (Strbac & Bopp, 2007) The cost associated with accommodating wind generation that is not fully capable to ride through faults were assumed to be composed of: (i) additional response cost, mainly fuel cost due to running the conventional plant at lower efficiency and (ii) additional fuel cost due to the substitution of conventional generation for wind generation curtailment, that occasionally may be necessary to maintain the feasibility of system operation. Furthermore, operating an increased number of generators part loaded and having to curtail some of wind generation increases CO_2 emissions that were also estimated.

Overall, the work carried out demonstrated that, if a significant amount of wind generation with relatively low robustness is to be installed this would lead to a very considerable increase in system costs in the case of the UK. These additional costs would be significantly higher than the expected cost of engineering necessary to provide fault ride through capability. The results of the studies performed suggest that requiring sufficient fault ride through capability for large wind power plants would be economically efficient.

4.3 Netherlands

4.3.1 Grid reinforcement, Connect 6000 MW I

In 2003 the Ministry of Economic Affairs of The Netherlands initiated a study on the effects of 6000 MW offshore wind on the Dutch grid. The peak load of the high voltage grid is 15.2 GW (2005). The best locations for 6000 MW wind power were determined based on cost analysis and the options to transport the power to the on-shore substation were investigated.

In the second part of the study, the consequences for the 150/380 kV grid of The Netherlands have been determined by a load flow study (Jansen & de Groot, 2003).

Results: Fig 32 shows the bottlenecks caused by the additional wind power. New and/or upgraded HV connections are suggested to mitigate the problems. Secondly, voltage control equipment is required. Investment costs were estimated at about 310 ME. If 30 % of the new or upgraded connections have to be cables instead of overhead lines the total costs rise to about 970 ME.

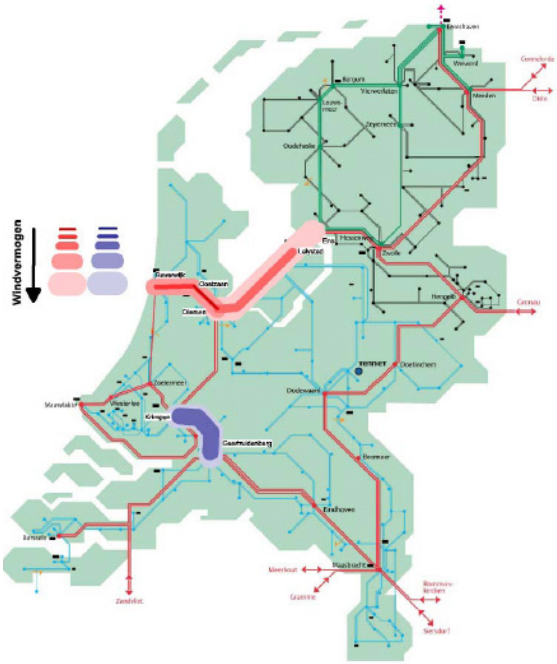


Fig 32. Offshore windpower induced bottlenecks in the transmission grid of the Netherlands.

Input data, wind power modeling: There is no wind model used. Amount of wind power changes up to nominal power.

Methodology: The consequences of 6000 MW offshore wind power on the 150/380 kV grid have been determined by a load flow study. The feed-in locations are Beverwijk and Maasvlakte.

4.3.2 Electrical infrastructure at sea, Connect 6000 MW-II

In 2005 the Ministry of Economic Affairs contracted a second study, Connect II. This study consists of scenarios for the implementation of wind power, pre-design and costs for the grid at sea as well as environmental, legal and political aspects. Here the part Electrical infrastructure at sea is summarized (Eleveld et al., 2005).

Methodology: The study comprises a further development of three of the options in the Connect 6000 study: 150 kV-AC, 380 kV-AC and HVDC Classic. For the 150 kV-AC a different case is studied than previously, viz. individual connection of wind power plants. For the 380 kV option two cases are studied: radial and ring structure. The HVDC option is also ring shaped. The main technical features of the options are determined, including aspects related to the sea-shore crossing. The investment costs of the options were determined and different economic scenarios were compared.

Results: Table 15 gives the net present value (Billion Euro) of the investments for a discount rate of 7 % and four development scenarios. The scenarios differ in the time to fully complete the total installed capacity.

Table 15. Net present value (billion Euro) of the investments for a discount rate of 7 %. In scenario 1 the total capacity 6000 MW is reached in 2020 whereas in scenario 2 in 2030.

	Scenario 1	**Scenario 2**
150 kV AC	0.96	0.77
380 kV AC star	1.01	0.80
380 kV AC ring	1.55	1.19
HVDC Classic	1.80	1.43

4.4 Portugal

4.4.1 Transmission grid development studies

Grid development due to high wind penetration goals was needed for two main reasons: need for the grid to be extended to collect wind power in areas of high wind potential and because wind power will increase the excess generation of several inner areas of the country. The ‘Transmission Grid Development Plan for Renewables – 2010’ was carried out in 2001, and its results incorporated in the grid planning decisions included in the Transmission Grid Plans that the TSO REN must present to the Regulator each two years. The original plan of 2001 was done by ‘Centro de Energia Eléctrica’, Department of Electrotechnical and Computer Engineering of the Instituto Superior Técnico (IST), Lisbon Technical University, and REN, SA.

Results: It will be necessary to build new transmission grid 400, 220 and 150 kV lines and substations, to uprate a considerable number of existing 220 and

150 kV lines, to increase the grid reactive compensation and to introduce phase shifter autotransformers in two substations. As for transmission grid integration costs, and for a level of 4000 MW, for the overall period 2005–2010, the investment directly attributable to renewables, mostly for wind parks, will total 200 Million €. That number:

- Is the sum of the proportion of the cost of each individual grid item (line, substation, etc.) directly attributable to the creation of grid capacity for renewables. We must take into consideration that most of the grid elements of this plan also will serve other grid objectives. Should we add simply the cost of all the grid items involved, the total cost would be around double (400 M€).
- Does not consider the investment of the wind park main substation nor the direct line to the TN connection point, which are built and paid by the developer.

Methodology: Usual AC steady-state simulation of the grid with PSS/E model of Siemens/PTI, the same used in 'classic' grid development studies.

Assumptions: Wind generation was set in three levels: 80 %, 30 % (average situation, used also to calculate expected losses in the grid) and 10 %. As for the other generation components, the usual planned scenarios were considered: 'Crossing' among the relevant: 1 – High hydro (less thermal) and dry situations (more thermal) 2 – Balanced and high interchange situations 3 – Extreme import or export values 4 – Loads are simulated in peak, valley and some intermediate load situations. It was also assumed that it is possible to uprate the ratings of some existing lines and that it is possible to consider the contribution of FACTS such as phase shifter autotransformers.

Limitations: When the first study was done neither the detailed location of the future wind power plants nor the pace of building was known. The TSO REN had to rely on the previous studies of location of wind potential. REN had to introduce some flexibility items in the planning solutions to cope with possible different outcomes in those two fronts.

4.4.2 Power system transient stability of the Portuguese grid

REN investigated, in 2004, the impact of the expected wind by 2010 on the transient stability of the Portuguese transmission grid, also in cooperation with

IST – Instituto Superior Técnico – Centro de Energia Eléctrica, and examined the need to specify new requirements for wind turbine generators (WTGs) to withstand voltage dips produced by short-circuits in the grid without disconnection.

Results: For some faults in a few specific busbars of the grid, a loss of synchronism may occur in some parts of the Iberian Peninsula grid, if the current practice of undervoltage protection in WTGs remain in the future. The implementation, in a significant percentage of the installed wind generation, of control equipment to ensure fault ride through capability (FRTC), results in a significant reduction in the disconnection of wind power.

It is relevant to note that the loss of wind power in Portugal has an impact on the Spain-France interconnection, which is normally operated with commercial exchanges from France to Spain.

Input data, modelling – Usual PSS/E dynamic simulation data with detailed Iberian Peninsula and French system equivalent. Special care has been taken in the simulation of each WTG technology.

Methodology – Usual transient simulation studies with the following assumptions:

Assumptions Three-phase faults cleared in time of the circuit-breaker failure protection and of 2nd step of distance protection (teleprotection failure), as well as the usual three-phase faults with 'normal' clearing times.

Limitations – WTG's models acceptable but not state-of-the-art. Wind penetration (2600 MW) smaller than later set national objectives.

4.5 Power system stability of the Iberian transmission grid

A study by Red Eléctrica de España, SA (Spanish TSO), 'Producción Eólica Tecnicamente Admissible en el Sistema Eléctrico Peninsular Ibérico – Horizonte 2011' with the participation of REN – Rede Eléctrica Nacional, SA, the Portuguese TSO, was concluded in 2006 and covered the transient simulation of the Iberian network in order to identify limits for wind penetration under the stability point of view.

Results: It showed that 20GW of wind power in Spain and 5 GW of wind power in Portugal are possible if fault ride through capability (FRTC) is reached for 75 % of the installed wind turbines. It also showed that there are no limits, due to transient stability reasons, should 100 % FRTC be possible.

Input data, modelling: Usual PSS/E dynamic simulation data with detailed Iberian Peninsula and French grids + 'Remaining UCTE system equivalent'. Special care has been taken in wind turbines modelling, getting models from manufacturers, in most of the cases under non-disclosure agreements.

Methodology: Transient simulations of the Iberian power system submitted to three-phase faults located in bus bars of the transmission network. Simulations of these faults are based in the operation of protective relays (REE, 1995) in the Spanish case. The simulation time is 20 s since the fault is applied. A peak demand scenario in winter and a valley demand one in summer are considered.

Assumptions: Three phase faults cleared in time of the circuit breaker failure protection and of 2nd step of distance protection (teleprotection failure) as well as the usual three faults with 'normal' clearing times. The clereance of three-phase faults are 250 ms in Spain and 250/300 ms in Portugal. The study is focused in 11 nodes (400 kV). All the wind farms operating in Spain are considered, distinguishing technology (induction generator –squirrel cage and wounded rotor– synchronous generator –full power converter– and doubly fed induction generator) and adding future wind farms. Future wind farms are modeled with wind turbines supporting voltage dips and complying the Spanish Grid Code. In simulated scenarios, a new 400 kV line between France and Spain has been considered which will increase the interconnection capacity between France and Spain from the current maximum of 1.5 to 4 GW.

Limitations: This new France – Spain interconnection reinforcement has not yet the environmental and administrative licences. The results assume that it will be possible to enhance a part of the existing wind turbines to FRTC. This will not be easy considering that in the Iberian Peninsula, more than 12 GW are already installed, many of which with 'old' technologies.

4.6 Spain

4.6.1 Power system transient stability and grid reinforcement

Different studies, (REE/REN 2005, Rodríguez-Bobada et al., 2006), were carried out by Spanish and Portuguese TSOs REE and REN to determine the maximum wind power capacity that the Iberian grid could handle (see previous section).

The importance of future 400 kV DC interconnection line with France was highlighted. In the Spanish case, wind power development has imposed new connecting and operating rules, being the connection and reinforcement costs paid by wind power plants (from the wind power plant to the electrical substation). On the other hand, this has provoked an updating in connecting requirements, protection equipment, remote metering and control, resolution of constraints or wind power plant clustering.

Obviously, transmission network must be updated as well; the investment 2200 Million €, not only attributable to renewable, has been estimated by REE for the overall period 2006–2010. In terms of investments due to wind energy, it is difficult to obtain the figures for the Spanish case, since grid reinforcements and new lines are needed for wind power plants and other clients (electrical demand growing rates have been high in the last years).

4.6.2 Low Voltage Ride Through capability for wind power plants

REE grid code, recently approved, specifies that the wind farm must support the grid during voltage dips, at the point of interconnection with the transmission network, without tripping. In (Gómez-Lázaro et al., 2007a) REE grid code is commented in detailed, justifying the different values imposed by the Spanish Grid code (Operational Procedure 12.3).

The procedure for measuring and assessing the response of wind farms submitted to voltage dips – specified in the electrical system Operational Procedure 12.3 – will be established in the “Procedure for measuring and assessing the response of wind farms in the event of voltage dips”.

This procedure can be accomplished with a general verification process or using a particular verification process. The general verification process consists on verifying that the wind farm does not disconnect and the execution of the requirements settled down in the OP 12.3, by means of the realization of the following actions:

- Wind turbine and/or FACTS tests in field, measuring their response during a voltage dip.
- Wind turbine and/or FACTS simulation and validation. Simulated results are compared with the measurements.
- Wind farm simulation. Wind farm model must include certified wind turbine models, together with the wind farm electrical installation – cables and transformers –, being the rest of the electrical system outside of the wind farm modeled as an ideal programmable voltage source. The

source must provide two different RMS voltage profiles – three-phase and phase-to-phase voltage dips. Assessment and certification of compliance of wind farm model is obtained when none of the wind turbines in the wind farm is tripped together with the fulfillment of active and reactive power requirements imposed by the Spanish grid code.

Clearly, wind turbine and wind farm models have an important role to play in the whole process. According to the requirements imposed by this procedure, complete wind turbine and wind farms models must be developed (Gómez-Lazaro et al. 2007b).

4.7 Denmark

There are two reports regarding grid reinforcement costs in Denmark required to achieve wind power production covering 50 % of energy consumption in Denmark in 2025 (Danish Energy Authority, 2007): EA Energinanalyse A/S, 2007 and Electricity Infrastructure Committee, 2008.

In April 2008 the Electricity Infrastructure Committee (including among others the Danish TSO Energinet.dk) published a report (Electricity Infrastructure Committee, 2008) indicating that in Denmark there is a large range for necessary future grid investment costs, depending on whether cables or overhead lines are used. The report distinguishes between 6 principles with different grade of cabling. During the same period up to the year 2030 another 3.5 GW of wind power will be integrated into the Danish electricity system, adding up to 6.5 GW installed wind power capacity in total.

The expansion costs for the 6 principles have a bandwith between 107–1910 €/kW, referring to the addidional 3.5 GW wind power, but not all of these costs can be allocated to wind power. In November 2008 the “principle C” has been choosen by the Danish government, resulting in 675 €/kW, referring to additional 3.5 GW wind, of which roughly 40 % can be allocated to wind power. Thus in Denmark the grid expansion costs due to wind power are estimated to be about 270 €/kW installed wind power capacity up to the year 2030.

Regarding the analysis of the network reinforcements in (EA Energinanalyse A/S, 2007):

Input data: Installed wind power capacity on-shore in 2025 will be 3500 MW, with an increase of 700 MW compared to 2008. Off-shore wind power capacity will be increased by 2250 MW. An estimate of the location of the off-shore wind parks has been made.

Results: The total costs of getting the wind power production to shore including transformer stations and AC/DC converters are 925 MEuro i.e. 0.41 MEuro/MW offshore wind (see Table 18 in (EA Energinanalyse A/S, 2007)). The required additional on-shore network reinforcements have a cost of 142.5 MEuro (0.063 MEuro/MW offshore wind) assuming an additional cable between Western Denmark and Norway is built (Skagerrak 4) for other reasons (see Table 19 in (EA Energinanalyse A/S, 2007)). If Skagerrak 4 is not established the network reinforcement costs increases to 263.4 MEuro (0.117 MEuro/MW offshore wind). Increasing onshore wind power with 700 MW from 2007 to 2025 is estimated to be possible without transmission grid reinforcements, although some local reinforcements in the distribution grid might be necessary.

Methodology: The analysis is not based on network simulations but on expert judgement. In combination with assumptions about the type of connection (AC or DC) between off-shore wind power plant and on-shore transmission grid, and costs assumptions in relation to cables, transformers and converters, this enables costs estimates to be made.

Assumptions: It has been assumed that all on-shore network reinforcements must be done with cables i.e. avoiding usage of overhead lines. The cost estimates are crucially dependent on the costs assumptions regarding cables, which are quite uncertain.

4.8 Norway

Report: (Korpås et al., 2006.) When planning wind power in areas with limited power transfer capacity, conservative assumptions may lead to unnecessary strict limitations on the possible wind installation. By introducing Automatic Generation Control (AGC) and coordinated power system operation, a large increase in installed wind power is viable. When assessing the impact of wind power on the power system operation it is necessary to take into account the stochastic and dispersed nature of wind power. This study and previous studies have shown that in the Nordic region, the periods with highest wind generation typically appear in the winter season when the consumption also is high, which has a positive impact on the utilisation of the existing transmission capacity. Moreover, this study shows that the power smoothing effect of geographically dispersed wind power plants gives a significant reduction of discarded wind energy in constrained networks, compared to a single up-scaled wind power plant site.

The specific case study presented consists of a regional power system with assumed 420 MW power transfer capacity (Fig 33). With existing hydro power installation of 380 MW and 75 MW minimum local, the most conservative approach limits the total wind power installation to 115 MW.

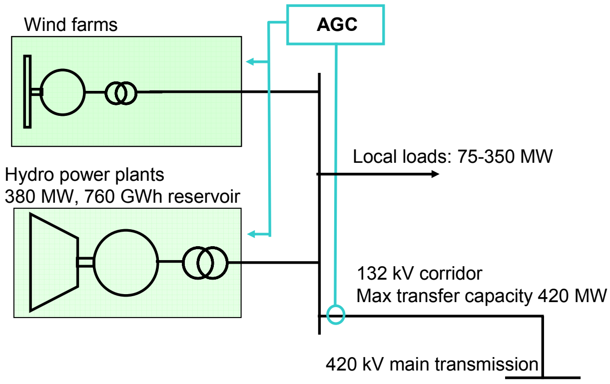


Fig 33. Overview of the case study power system. The regional grid is connected to the 420 kV national grid via a corridor of several 132 kV lines. Automatic Generation Control (AGC) is regarded for keeping the power transmission below the maximum export capacity of 420 MW.

Method: A simulation model of the regional power system has been implemented in MATLAB. To run the simulations of the regional power system, 30-year time-series with hourly resolution has been constructed for the following time-varying parameters:

- normalised wind power output (non-congested) from three wind power plants
- electricity consumption
- storable inflow
- non-storable inflow
- scheduled hydro generation
- electricity market price.

For the construction of wind power time-series for each wind power plant site, a common 30-year wind speed series with weekly resolution has been combined with the 1-year wind speed series with hourly resolution. The weekly wind speed series is scaled to give a 30-year average of 10.5 m/s. The 1-year time-series is normalised and multiplied with the weekly wind speed averages to give an 8760 hour x 30 year matrix of wind speed which is converted to power by using a typical wind turbine power curve. The sum hourly wind generation is simply calculated as the sum of power generation from the three wind power plants.

The other time-series listed above have been constructed by using the EMPS-model (Multi-Area Power Market Simulator), a commercial model developed at SINTEF Energy Research in Norway for hydro scheduling and market price forecasting. This is a complex stochastic optimisation model that simulates the optimal operation of the hydro power resources in a region with a stochastic representation of inflow to the hydro power stations and a number of physical constraints taken into account. The electricity consumption has been modelled as temperature-dependent, causing some yearly variations. Long-term increase in consumption has not been considered. An EMPS-simulation of the Nordic power system has been run without wind power in the area of interest, to provide a basis for the hydro power scheduling as well as the electricity market price.

It is possible to use EMPS to simulate the Nordic power system with geographically dispersed wind power, especially to assess the value of wind power in the electricity market and to determine the effects of large-scale wind power integration on optimum long-term hydro scheduling. In this case, on the other hand, EMPS is less suitable mainly because of the low time resolution of the EMPS-model (one week) and the limited flexibility of defining control strategies for wind-hydro coordination in an area with considerable transmission constraints.

Since the time resolution of the output from EMPS is one week, the hour-to-hour variations of consumption, inflow, hydro generation and price has to be synthetically generated. The hourly values of the consumption and hydro generation have been constructed as products of the weekly average values and typical diurnal variations observed in the Nordic power system. The hourly values of the other parameters (storable inflow, non-storable inflow and price) are simply constructed by interpolating the weekly values.

Result: The study shows that for the specific system studied up to 600 MW wind power is possible without noticeable reduction in income from energy sales compared to an ideal non-congested case, by applying coordinated operation of the wind and hydro power plants (Fig 34). It is emphasized that this is achieved for a hydro power system with relatively small reservoir and a high share of non-storable water inflow (37 % of the total storable + non-storable inflow). Even if the local hydro power plant follows the generation schedule unaffected by wind power, the reduction in income due to discarded wind energy is as low as 1–5 %, depending on the annual wind speed and water inflow.

It is concluded that power system coordination allows for surprisingly large amounts of wind power. It is essential to take account for the power system flexibility and the stochastic and dispersed nature of wind power. The presented methodology facilitates this and represents a rational approach for power system integration of wind power plants in areas with limited transfer capacity.

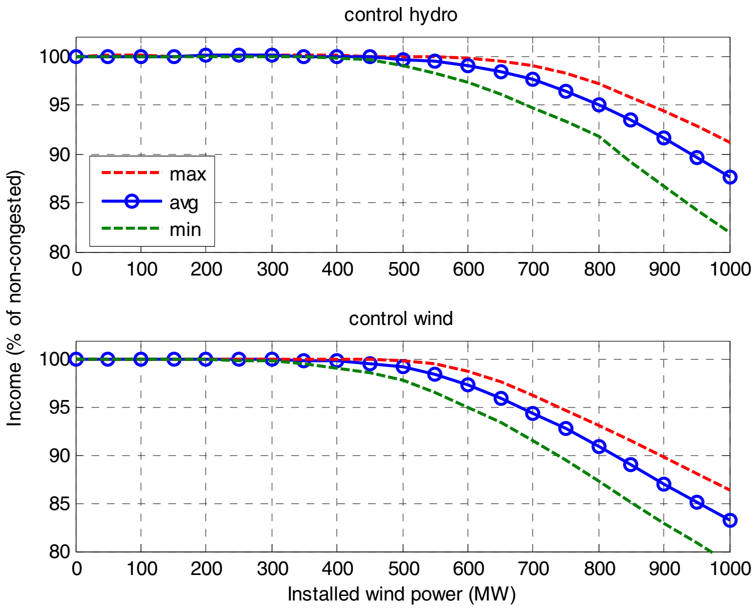


Fig 34. Annual income (wind+hydro) from energy sales to electricity market relative to the non-congested case.

4.9 Sweden

PhD study by Julija Matevosyan "Wind power integration in power system with transmission bottlenecks", 2006. Study: Economical evaluation of the value of transmission expansion to limit wind power spillage. (Matevosyan, J. 2006.)

Results: With no grid extension the spillage resulting of different wind power installations in northern Sweden are presented in Table 16.

Table 16. Estimated wind energy spillage in North Sweden without grid investments, calculated with two methods.

Installed wind power [MW]	Transm. limit exceeded [h]	Spill, % (discrete probabilistic method)	Spill, % (direct method)
1000	94	1.9	0.8
2000	453	5	3.4
3000	750	10.1	7.4
4000	1019	16.7	12.4

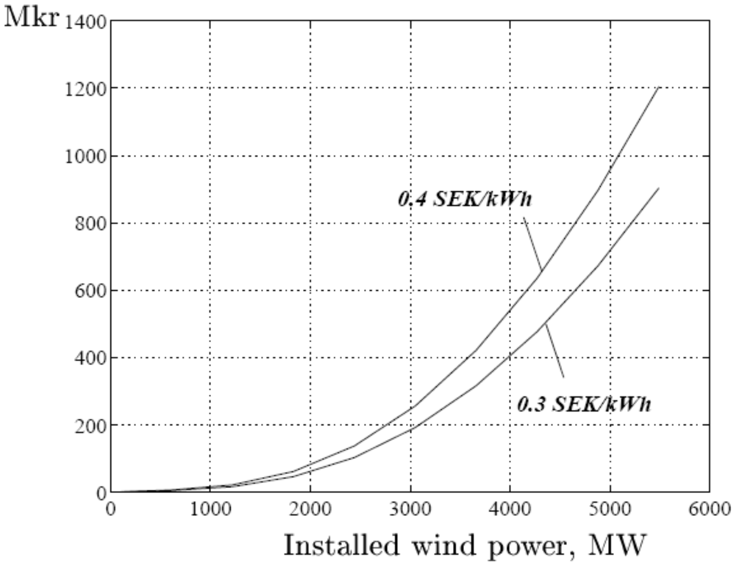


Fig 35. The cost for the spillage as a function of installed amount of wind power for two price levels of the spillage.

4000 MW of wind power will lead to 15.4 % of wind energy being curtailed with cost of approximately 540 MSEK/year with the curtailment cost of 0.4 SEK/kWh (Fig 35). For 3200 MW it is 300 MSEK/year. Consequently, a new 800 MW transmission line decreases costs for energy spillage to 540–300 MSEK/year. The cost for the needed 800 MW transmission line is for this case 400 MSEK/year. For this case it is therefore not motivated to build a new line just to motivate lower wind energy spillage. It can though be noted that a required interest rate of 10 % has been used for this transmission line investment which is comparatively high.

Input data, modelling: Line cost data, current use of actual transmission corridor, interest rate for transmission line investment, duration curve of possible wind power production. Cost of wind energy spillage.

Methodology: Simplified calculations based on duration curves and available time series.

Assumptions: No use of local hydro power storage (or any other kind of local use of wind power) in Northern Sweden to store excess wind power. If this is considered (which is done in the thesis) then the value of increased transmission will decrease even more.

Limitations: A specific study for this certain region, where an extension of a large corridor with 7000 MW capacity is considered.

4.10 Ireland

In the past five years Ireland has done extensive work on developing wind grid codes both at the transmission level (EirGrid Grid Code, 2008) and at the distribution level (Distribution Grid Code, 2007). These codes require detailed dynamic models and Ireland has been at the forefront of these developments and these are reported in (Coughlan et al., 2008). The Irish system operator EirGrid recently launched a report detailing the need for a comprehensive upgrade of the Irish Transmission system involving the replacement or upgrading of over 2000 km of transmission lines and the construction of over 1000 km of new transmission. These figures are in large agreement with the results of the network part of the All Island Grid Study (All Island Grid Study, 2008) summarised below.

Results: The network part of the All Island Grid Study found that for Portfolio 1, which includes 2.25 GW of renewables, of which 2 GW is wind, modest amounts of additional high voltage transmission are required. For higher levels of wind, substantial transmission reinforcement is required (Table 17). For Portfolio 5 (6.6 GW of renewables including 6 GW wind) total capital investment in transmission of in excess of €1000 million will be required. This represents a total investment of €154 per kW of renewable generation installed. The incremental transmission investment required to integrate the 4.3 GW tranche of renewable beyond Portfolio 1 amounts to €212 per kW of renewables. When annualised these costs were modest adding of the order of 1 or 2 % to the cost of electricity even in the highest wind portfolios. The single biggest issue will be getting public acceptance of the transmission. Significant reactive power issues were identified that will need to be addressed more fully.

Table 17. Transmission cost results for All Island Grid Study. The overall incremental cost to go from 2254 MW to 6560 MW is €212/kW.

Installed Renewable Generation MW	Total Transmission Investment Cost (€M)	Transmission Investment Cost per kW installed (€)	Incremental Transmission Investment Cost (€M)	Incremental Transmission Investment Cost per incremental kW installed (€)
2 254	92	41	-	-
4 254	668	157	576	288
6 560	1 007	154	339	147

Input data, modelling: A model of the All Island power System was provided by the system operator Ireland EirGrid and System Operator Northern Ireland.

Methodology: A comprehensive modelling approach was used that involved a first pass using a DC load flow analysis. There was also a large number of cases run to try and get away from a purely determinist planning approach. Full AC analysis was also carried out. The methodology also attempted to identify network upgrades that were driven only by the increase in renewable (mainly wind).

Assumptions: No detailed dynamic studies or short circuit studies were conducted.

Limitations: The study was not a full planning study but more a high level assessment and did not for example take account of maintenance issues.

4.11 Finland

Grid reinforcement needs for two scenarios for wind power in Finland were estimated in the Master's Thesis of Jarno Lamponen, 2008, reported also as EWEC'2008 paper (Lamponen et al., 2008). 2000 MW corresponds to about 5 % of gross demand in Finland and 7320 MW nearly 20 % of gross demand.

Results: The costs were calculated first by all required reinforcements to existing grid in Finland. Secondly only that part of the reinforcements were taken into account that are not already planned for also other reasons than wind power (Fig 36). The prices include only the costs for reinforcing the grid.

Wind power scenario	All costs	All costs / MW
7320 MW	394 M€	54 k€
2000 MW	149 M€	74 k€

EXTRA GRID REINFORCEMENT COSTS CAUSED BY INSTALLATION OF WIND POWER

Wind power scenario	Costs	Costs / MW
7320 MW	253 M€	35 k€
2000 MW	8 M€	4 k€

Fig 36. Results from estimated grid reinforcement needs for 2000 and 7320 MW wind power in Finland. The lower costs are calculated ignoring the costs of already planned grid reinforcements. These costs are not valid if the grid is generally developed differently than estimated in this study.

Input data, modelling: A model of the Nordic Power System was provided by the system operator Fingrid.

Methodology: Wind farms were connected to existing substations. New 110 kV or 400 kV lines were added if overloadings or voltage declines occurred in the intact grid or after (n-1) faults in the PSS/E simulations. For wind turbines, the DFIG-model from the PSS/E Wind Package was used.

Assumptions: It has to be stressed that the transmission grid is designed according to objectives of this study and they do not necessarily correspond with plans made by the system operator Fingrid. These costs are not valid if the grid is generally developed differently than estimated in this study.

Limitations: The results are not from a comprehensive study – no alternatives were calculated and only limited analysis on dynamic impacts was made, as this was a Master's thesis only. Grid reinforcement costs are by nature dependent of the existing grid. The costs vary with time and are dependent on the time instant the generator is connected. After building some lines, often several generators can be connected before new reinforcement needs occur. After a certain time instant, new lines, substations or something else is needed. The same wind power plant, connected at different time instant, therefore may lead to completely different grid reinforcement costs. In this study the grid was not planned in the way it is usually made: comparing different alternatives. In this Master's thesis only one possible grid investment plan was used. Therefore these figures should not be used for any other purposes than just one example of one possible case at one time instant.

4.12 USA

The US grid code for issues dealing with the interconnection of wind turbines in projects greater than 20 MW is addressed in FERC Order 661-A, issued in December of 2005. The major provisions of the order address requirements for low-voltage-ride-through LVRT, reactive power, and SCADA. For LVRT, the generator is required to stay on line during a 3 phase fault for normal fault clearing time up to 9 cycles and single line-to-ground faults with delayed clearing during a voltage dip as low as 0.15 pu at the high side of the generator step-up transformer for units in service before 2008. The voltage dip requirement extends to 0.0 pu in 2008. For reactive power requirements, the wind plant must provide power factor of +/- 0.95, including dynamic voltage support, if needed for safety and reliability. For SCADA, the wind plant must provide the necessary information, as agreed upon with the transmission provider. This information may include some combination of electrical parameters and weather data.

4.12.1 Stability studies – New York and California

The impact of wind generation on system dynamic performance is illustrated in Fig 37 (GE Energy, 2005). The simulation is for a normally cleared three phase fault on a critical 345 kV bus in New York State. The simulation assumed a 10 % wind penetration (3,300 MW on a 33,000 MW system) of doubly fed induction machines with vector controls. As can be seen from the simulation results using the GE PSLF program, the post-fault voltage recovers more rapidly and is more highly damped with the wind plants than without, and the line flow has less over-shoot and is more highly damped.

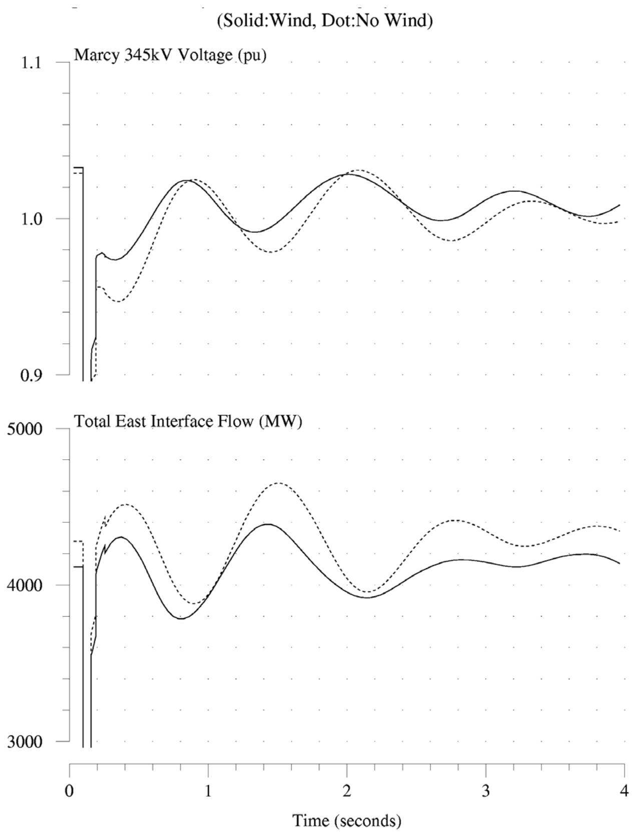


Fig 37. Impact of Wind Generation on System Dynamic Performance.

The November 2007 CAISO report (Loutan et al., November 2007) investigated the need for reactive support in the Tehachapi area of California, where 4200 MW of new wind generation is planned. It was found that if doubly fed asynchronous generators or full output converter machines were assumed, with their inherent dynamic reactive capability, the additional static var compensators assumed in the transmission system design study would not be required, provided that all new wind generation units have the capability to meet the WECC requirements of ±0.95 power factor, with an appropriate mix of static and dynamic var capability. Additional analyses will need to be performed to determine the minimum requirements for the dynamic range. This suggests that wind plants with some dynamic reactive capability may reduce or eliminate the need for dynamic reactive devices on the transmission system.

4.12.2 Transmission infrastructure – California and Texas

The transmission infrastructure findings of the CEC study for California (Porter et al., 2007) showed that significant new transmission would be required to move the remote renewable energy to load centers. Wind variability may contribute to increased transmission congestion. Greater geographical diversity in wind generation will result in increased transmission utilization. On the policy front, greater use of wind plant output forecasting on all time scales is encouraged. Practices to increase utilization of existing transmission, such as real-time ratings, nodal injection forecasts, and coordinated controls are encouraged. Under rare circumstances of coincident minimum load, high wind generation, and low conventional hydro flexibility, curtailment of variable renewable energy generation may be necessary.

Update on the Texas CREZ Transmission Process: Over the last decade, the State of Texas has mandated that retail providers obtain specified amounts of renewable energy to meet customer demand for electricity. The Texas Renewable Portfolio Standard (RPS) has been very successful and goals were met early with large amounts of wind capacity installed. However, since wind developments are primarily in West Texas or in the Panhandle, while loads are in the east and central parts of the state, wind developers soon ran out of existing transmission capability for delivery. System operator curtailments were often ordered for wind plants.

The conventional transmission planning processes have failed to resolve the limited transmission capability for these wind plants. The problem was that under existing protocols, wind developers that requested service often did not have the financial capability to post the guarantee deposits needed for utilities to build new high voltage transmission investments. At the same time the transmission utilities were not able to build the needed transmission because there is no surety that the wind project will be developed to use the transmission and cost recovery was in doubt. Thus, a new solution was needed to assure needed transmission access for new wind.

Texas has instituted the CREZ (Competitive Renewable Energy Zone) process to address the need for and cost recovery of new transmission for large amounts of wind and perhaps other renewable technologies. Under the CREZ process, the Public Utility Commission of Texas (PUCT) was charged to identify zones with high wind potential (Fig 38). These zones, designated by the PUCT with advice and analytical support from the Texas grid operator (ERCOT), receive special treatment under law. Of four future scenarios examined for transmission needs covering 12,000 to 24,000 total MW's of wind, the PUCT in 2008 selected Scenario 2 which provides access for about 18,000 MW of wind. Cost for this transmission is to be recovered across all load-serving-entities.

Scenario 2 envisions the construction of about 1,400 miles of new double circuit 345 kV lines, about 1,000 miles of single circuit 345 kV lines, addition of series capacitors along with transformers and termination equipment. The estimated cost for the facilities is almost $5 billion. A diversified group of Texas transmission providers filed a proposal with the PUCT in September, 2008, for the construction of Scenario 2 transmission.

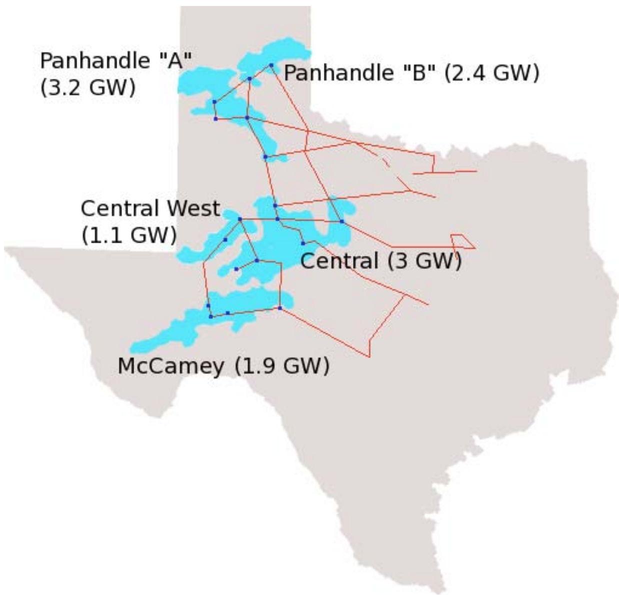


Fig 38. Map of the CREZs in ERCOT designated in PUCT (2008), the expected wind generating capacity of the regions, and new transmission pathways.

4.12.3 US Transmission Expansion Cost Summary

The Lawrence Berkeley National Laboratory has recently reviewed a sample of 40 detailed transmission studies that have included wind power. These studies cover a broad geographic area, and were completed from 2001–2008. The primary goal in reviewing these studies was to develop a better understanding of the transmission costs needed to access growing quantities of wind generation.

These studies vary considerably in scope, authorship, objectives, methodology, and tools. As such, it is not appropriate to try to make comparisons among the studies, but rather to simply investigate the range of transmission costs found in accessing a variety of wind resources under a variety of conditions. The analysis focuses primarily on the unit cost of transmission implied by each of the studies. The unit cost of transmission for wind in \$/kW terms on a capacity-weighted basis is estimated by simply dividing the total transmission cost in a study by the total amount of incremental generation capacity (wind and non-wind) modeled in that study. The limitations of the approach are described in some detail in the body of the report (Mills et al., 2009).

The studies that specifically analyze wind power capacity examine wind additions that range from as little as 63 MW to as much as 236 GW. The total range of transmission costs for wind investigated in these studies is quite large, ranging from \$0/kW to over \$1,500/kW. The majority of studies, however, have a unit cost of transmission that is below \$500/kW, or roughly 25 % of the \$2,000/kW cost of building a wind project. The median cost of transmission from all scenarios in the sample is \$300/kW, roughly 15 % of the cost of a wind project today. One of the most interesting findings from the study is that unit transmission costs of wind do not appear to increase significantly with higher levels of wind penetration. Rather, studies with the highest additions of wind energy tend to have lower unit costs of transmission, indicating that economies of scale appear to come into play when accessing large resource areas.

In this regard, the report compares the bottom-up transmission project costs above to three recently completed top-down studies. The cost of transmission in two of the three studies is at or below the median cost in the sample of bottom-up studies (\$300/kW). Specifically, the two studies that evaluate transmission to enable a 20 % wind energy scenario in the U.S., the AEP Interstate Transmission Vision and the NREL Wind Deployment System (WinDS), have a unit cost of transmission of \$150-\$300/kW and \$207/kW, respectively. Notably, the unit cost in these two top-down studies compares favourably to the unit cost of transmission for wind found in a recent bottom-up study of a 20 % wind energy scenario for the Eastern Interconnection, the Joint Coordinated System Plan (JCSP), which was \$195/kW. In the National Energy Modeling System (NEMS) maintained by the Energy Information Administration (EIA), the wind capital cost adjustment factors and base transmission costs used to reflect transmission costs and other factors loosely imply an average unit transmission cost of

$450/kW for 40 GW of new wind by 2030, 50 % higher than the median value found in the studies reviewed in the report.

4.13 EU project Tradewind

An assessment of the options for improved interconnection and power market design to enable large-scale wind energy integration in Europe was done in the TradeWind Project (2006–2008) co-ordinated by EWEA, sponsored by the European IEE Programme (Van Hulle et al. 2009). Scenarios (Low, Medium, High) of distributed wind power capacity have been assumed – anchored at the years 2010, 2015, 2020 and 2030, corresponding with installed capacities of 200 GW and 300 GW for the Medium Scenario in 2020 and 2030. Power flow simulations were carried out to look into the effects of possible grid dimensioning situations due to meteorological events, such as the passing of deep low pressure systems which are expected to cause large wind power production variations and hence measurable changes in cross border flow. In parallel, main transmission bottlenecks were identified, with special attention to the interconnectors of 'European Interest' according to the TEN-E programme. The effects and economical benefits of network upgrades that would relieve existing and future structural congestion in the interconnections were assessed. The project looked also specifically at transmission configurations for integrating offshore wind power, including transnational offshore grid topologies.

Results: The simulations show that increasing wind power capacity in Europe leads to increased cross-border energy exchanges and more severe cross-border transmission bottlenecks in the future. Especially with the amounts of wind power capacity expected in 2020 and 2030, congestion on the borders of France, between GB and Ireland, on several borders of Sweden, Germany, and Greece is more severe. Wind power forecast errors result in deviations between the actual and expected cross-border power flows on most interconnectors during a substantial part of the time and will further exacerbate these congestions. As far as meteorological events are concerned, cross-border transmission is not significantly affected by wind power fluctuations for most of the European countries for installed wind capacity scenarios up to year 2015. Even if wind power plants are cut off due to rare storm occasions and a dramatic drop of production occurs in one country, the effect was not so much seen at a European scale. However it was found that the model resolution was not high enough to properly study these effects, which could become significant with higher penetrations.

TradeWind has identified 22 onshore interconnectors and a corresponding time schedule for upgrading that would benefit the European power system and its ability to integrate wind power. The cost savings for power system operation corresponding to the upgrades were quantified assuming a perfect market and amount to 1500 M€/year, justifying investments in the order of €22 billion, for wind power scenarios up to 2030.

A meshed offshore grid is proposed linking future offshore wind farms in the North Sea and the Baltic Sea and the onshore transmission grid, based on an installed wind power capacity of 120 GW, which according to a preliminary economic analysis compares favourably to a radial connection solution. Such offshore grid supposes further upgrade of the onshore network. Highly congested mainland connections were observed internally in Germany and Sweden, and interconnectors between Belgium and the Netherlands and between Belgium and France.

Input data, wind modelling: The geographically distributed wind power capacity scenario data were combined with Reanalysis wind speed data to produce hub height and terrain specific wind power time series, with a time step of six hours linearly interpolated to one hour for a grid spanning the whole area of Europe studied. Where necessary, correction factors were applied to get reasonable agreement with observed and expected long-term capacity factors for wind generation in specific areas including the most important wind energy countries and offshore regions.

Methodology: The power flow in the EU high voltage grid was analysed with a simplified DC flow based market model (opf), representing the European power system as a single, perfectly functioning market. Equivalent network representations were used for the UCTE, Nordel, GB and Ireland synchronous zones. To provide a degree of validation, the simulation results have been compared with actual cross-border exchanges and with results from a more detailed model of the UCTE network (UCTE 2008 Summer and Winter Research Model), made available at the end of the project.

Assumptions: The model assumed a perfect market, where generators are dispatched according to merit order.

Limitations: In view of limited availability of network data, especially for the UCTE area, intra-zonal transmission constraints were very limited, restricting cross-border flow mainly by individual tie-line capacities and net transfer capacity (NTC) values. It was not intended to make an in depth grid dimensioning study nor to consider dynamic grid behaviour and reliability aspects such as N-1 considerations.

4.14 European Wind Integration Study EWIS: Phase one, 2006

European Transmission System Operators launched a European wide grid study on the integration of wind power in 2006. The scope of work covers the technical, operational and market aspects related to the smooth integration of large scale wind power all over Europe. The study focus is on measures needed to be taken by legislators, regulators, grid operators and grid users, to enable establishing a harmonised set of rules for the integration of wind power, which is vital for secure and reliable operation of the electricity networks in the presence of variable generation. Phase one of the project has analysed cases for year 2008. Phase two will investigate the time horizon up to 2015. The study will obtain the necessary information for the technical and operational measures for risk mitigation and the secure operation of the European electricity grid, identified by the steady-state and dynamic investigations on electricity grid models (EWIS, 2007).

Results: First results show that expansion of wind power generation has significant effects on the European electricity system. Wind power is concentrated in Europe: 70 % of the installed wind power is concentrated in only 3 countries. This is producing a high surplus of power generation in regions like northern Europe resulting in large North-South power flows through the transmission system of Germany and neighbouring countries e.g. the Netherlands, Belgium, Poland and Czech Republic. Serious bottlenecks on internal and cross-border lines in northern Europe are detected already today, becoming more structural for the time horizon of 2008. Internal overloads are observed in Germany, Czech Republic, Poland, Belgium and the Netherlands for single circuit outages in case of high wind power production in northern Europe.

Investigated measures for the time horizon of 2008 to prevent these overloads are described in the EWIS interim report (EWIS, 2007).

Input data, wind power modeling: Using existing time-series (15-minutes-values) of the wind power production, a point in time with the highest simultaneous wind power production in the northern UCTE countries was identified for UCTE Scenario North. For UCTE Scenario South the highest simultaneous wind power production in southern UCTE countries was identified.

For each country an individual level of wind power generation was then determined. In order to extrapolate the data into the year 2008, the expected wind power installed in each country in 2008 was used. Synchronous time series were available from Germany, Spain, Portugal, Denmark, Austria and Belgium. In circumstances where no time-series of wind power production data was available, the wind power production was estimated from wind speed measurements of numerous weather stations in the countries.

Assumptions: Year 2008 wind scenario: The study comprises two wind situations with major impact on the operation and security of the European transmission network:

- Wind Situation UCTE North: Maximum wind power production of northern UCTE countries (Austria, Belgium, Czech Republic, Denmark, North-France, Germany, Hungary, Netherlands, and Poland).
- Wind Situation UCTE South: Maximum wind power production in southern UCTE countries (South-France, Greece, Italy, Portugal and Spain).

Limitations: The precise impact of phase-shifters on cross-border bottlenecks will be further analysed in later studies. Without the use of phase-shifters, overloads of tie-lines are observed between Germany and the Netherlands, and Germany and Poland. By adjusting the settings of the phase-shifters in the Netherlands, Germany and Belgium to limit cross-border flows, the overloads of the tie-lines between the Netherlands and Germany can be reduced in 2008. Overloads near the Dutch-Belgian border can also be reduced with the use of phase-shifters in Belgium. Considering the already planned network expansion inside Germany, overloads of the interconnection between Poland and Germany do not occur any more. Until the realisation of the new 380 kV double overhead line between Neuenhagen and Bertikow, which is planned for 2009, a set of temporary operational measures can be taken in order to ensure operational security.

Internal bottlenecks: High wind power generation combined with high power production of conventional power plants with comparatively low marginal costs in the North of Germany and additional large import from Nodel system results in large North-South power flow in Germany. This causes several internal overloads during N-1 conditions. Internal overloads are also observed in Czech Republic, Poland, Belgium and the Netherlands for N-1 conditions in UCTE Scenario North. Investigated measures to eliminate these overloads are described in the detailed analysis.

5. Power system adequacy and capacity value of wind power

Power system reliability consists of system security and adequacy. A power system is adequate if there is a sufficient installed power supply to meet customer needs. A system is secure if it can withstand a loss (or potentially multiple losses) of key power supply components such as generators or transmission links. This chapter focuses on the impact that wind generation has on generation adequacy. Transmission adequacy is the issue in chapter 4.

The analyses for system generation adequacy are made several weeks, months or years ahead and associated with static conditions of the system. This can be studied by a chronological generation-load model, that can include transmission and distribution capacities and constraints, or by probabilistic methods. The data required to make the required generation estimation includes the system demand and the availability data of generation units.

Capacity value (sometimes called capacity credit) is the contribution that a given generator makes to overall system adequacy. Even the availability of conventional generation is not assured at all times because there is always a non-zero risk of mechanical or electrical failure. Because reliability is expensive it is common to adopt a reliability target for the system. The capacity value of any generator is the amount of additional load that can be served at the target reliability level with the addition of the generator in question.

The next section of this chapter discusses methods that are used to assess wind capacity value. The following sections provide a brief summary of results from countries that have performed capacity valuation of wind generation.

5.1 Approaches to assessing wind power capacity value

Although there are several methods used to calculate wind capacity value, most methods are based on power system reliability analysis methods.

The criteria that are used for the generation adequacy evaluation are based on Loss Of Load Expectation (LOLE), Loss Of Load Probability (LOLP) or Loss Of Energy Expectation (LOEE) calculations, for instance. LOLP is the probability that the load will exceed the available generation at a given time. The criterion is defined as the cumulative LOLP results, for each time step over a period of time, being lower than a certain level. LOLP as a definition gives the amount of time of system malfunction but it lacks information on the importance (severity /amount of MWs missing) of the outage. LOLE may be either the number of hours, usually expressed in hours per year, during which the load will not be met over a defined time period or the number of days, usually expressed in days per year, during which the daily peak load will not be met over a defined time period. LOEE is the number of MW-hours, usually per year, of load that will not be met over a defined time period.

During the course of system operation through the year, generating units can be in one of several states. Units are scheduled for maintenance at regular intervals, and this is typically scheduled during non-critical system periods. However, it is always possible that any generator could fail unexpectedly at any time of the year. The unexpected nature of these forced outages is the primary concern and focus of reliability analysis. Contingency reserves (sometimes called disturbance reserves) are provided to ensure against system collapse in the event of a fault on the system that may induce a generation or transmission forced outage. System adequacy assessments must take scheduled and forced outages into account, although the different types of outages are treated very differently in the reliability models. Additional consideration includes generating constraints that are generally treated as non-usable capacity. The uncertainties on hydro system constraints, resulting from inflow variability for both run of river and reservoir hydro power (and pumped storage, if available) should also be considered. In addition, there are uncertainties associated with the load forecast. Other system services, like reactive support to the system, may also be considered in the reliability models. Thus generating capacity, after the deduction of various sources of unavailability – non-usable capacity, scheduled and unscheduled outages – and reserves required by TSOs for system services (UCTE, 2005) are all considered in the reliability calculation. The level of remaining capacity (RC) necessary to provide a required level of supply adequacy must be estimated taking into account the characteristics of the power system. Fig 39 shows the components of the power balance in a system for a forecasted peak load. In general, this kind of graphical representation assigns the installed wind capacity partially to the so-called "non usable capacity" and partially to "guaranteed capacity"[1]. The proportion reflects the capacity credit assigned to wind power. Unfortunately, several prominent system adequacy reports (UCTE, VDN) still fully allocate wind power to "non usable capacity"[2]. System risk as measured by various reliability metrics is reduced for each additional MW of generating capacity that is online, whether scheduled or not. We therefore recommend that a reliability-based calculation should be used to address wind capacity value.

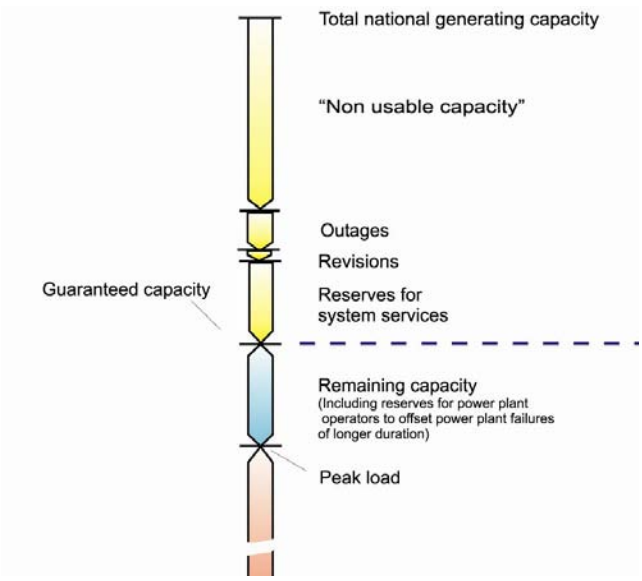


Fig 39. Power balance in the moment of peak load (adapted from VDN2005).

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1 Because no capacity can be absolutely guaranteed, we use this term to denote the capacity that is available with a given probabilistic target. This target is commonly measured as loss of load expectation (LOLE). A common reliability target for a system is 1 day in 10 years LOLE. The capacity that can provide this target, or other suitable target, is what we call 'guaranteed capacity.'

2 UCTE definition of non-usable capacity: "Non-usable capacity is the part of generating capacity which cannot be scheduled, for different reasons: a temporary shortage of primary energy sources (hydroelectric plants, wind farms) …." (http://www.ucte.org/statistics/terms_power_balance/e_default_definitions.asp)

To determine system adequacy, a desired level of achievable reliability is chosen (Ensslin, 2006). A commonly used reliability target is 1 day per 10 years outage rate, known as the loss of load expectation. In different national specifications, reliability levels are found ranging from a 99 % level (see Dena, 2005, for Germany) to a 91 % level (Ilex & Strbac, 2002, UK). The 'risk level' refers to a probability of the power system under investigation not to be able to cover its peak demand without electricity import. Here "without import into the system" needs to be highlighted. It means that the load being greater than the total system generating capacity minus the non-usable capacity, the capacity on outage and reserve do not automatically lead to a load shedding in the system. Instead, cross border transit capacities have to be used – a fact that links adequacy to market and regulatory aspects.

The 'guaranteed' or reliable conventional generation capacity is calculated by the combination of all individual power plants' probability of availability which can be calculated using the forced outage rate. This is based on the assumption that outages of individual generation units are statistically independent. The probability of generation unit forced outages vary for individual generation units between 1 % and 10 % of the time, depending upon technology, age and size of the plant (see for example statistics from operation in Germany, (Dena, 2005)).

The methods used to evaluate the capacity value of any generator may vary amongst the jurisdictions. One key capacity value metric is the Effective Load Carrying Capability (ELCC), which is the amount of additional load that can be served at the target reliability level with the addition of the generator in question. To calculate this metric, two reliability model runs are required. Each run may require several iterations to achieve the various reliability targets. First, the model is run to ensure that the reliability target can be attained. If the system does not achieve this reliability level, generation must be added or load decreased (or both changed) to achieve the target. Second, the generator is added to the modelled system and the load is increased so that the reliability level matches the one from the first step. The increase in load is the ELCC, or the capacity value of the generator. It must be noted that the metric "guaranteed capacity" is not the same as "ELCC". For example the adequacy level is not calculated with "guaranteed capacity" since the probability of different load levels is not included (Amelin, 2008).

Another method in usage is to measure the capacity value of a generator relative to a perfectly-reliable generating unit or to a benchmark unit. To calculate these metrics, three reliability model runs are required. First, the model is run to ensure that the reliability target can be attained, as in the previous method. Second, the generator (wind) is added to the modelled system. The new higher reliability value (lower LOLP, LOLE or LOEE) is recorded. Third, the generator (wind) is removed from the model and then either a perfectly-reliable generating unit or a benchmark unit is added to the system so that the reliability level matches the one from the second step. The generation addition from this step is the capacity value of the generator. One variation on this method consists of decreasing the load in the third step instead of adding generation.

There is a slight difference in the results from those methods as the load added in the second step of the ELCC metric calculation has variability and uncertainties associated with it and as the benchmark unit has a forced outage rate. Decreasing the load in the third step of the second method also leads to a different result than in the ELCC metric calculation as the results are not linear.

As the reliability criteria are demanding ones (ex. : 1 day in 10 years means a 0.027 % probability assuming a whole day outage), the capacity value is quite sensitive to the timing of wind energy delivery relative to peak load periods or other hours at risk. In addition, weather influences both electricity consumption and wind power generation. Although it may be difficult to directly calculate the statistical correlation between them, there are certainly complex interrelationships between wind and load. Even in cases with wind separated from load centres by relatively large distances, the weather correlation may consist of a complex lag structure that varies based on time and weather conditions. Finally, the most stressful system peak loads may be related to massive stagnant air systems, very hot and humid or very cold, when there is no or low wind or the wind turbines are stopped because of out of spec temperatures. Because of these, it is critically important to use wind and load profiles that result from a common weather driver to calculate wind capacity value. In a practical sense this means that at least one year of hourly wind generation and load must be obtained from the same calendar year. Because wind generation profiles and energy capture can vary from year to year as long as the most stressful system peak loads are related to infrequent extreme weather conditions, it is necessary to assess wind capacity value on multiple years (minimum 10 years and ideally 30 years) of time-synchronized wind and load data.

Some countries assess a capacity cost for wind energy – however this is not widely used. If cost estimates are made for the lower capacity value of wind power compared to thermal power plants, it is important to make a correct comparison. The utilization time of wind power is often in the range of 2000–

3000 hours per year, while it for base load thermal power often is 6000–7000 hours. This means that one has to add much more capacity for wind power compared to thermal power in order to get the same amount of energy per year. The comparison of alternatives for energy production for the power system must then be made on the same basis, that is, produced energy per year. This is the normal unit when one compares costs. The capacity value of wind power is often only slightly lower than the capacity value of a thermal power plant with the same yearly energy production. The deviation between these two capacity values is sometime denoted “capacity cost”. The “capacity cost” formally means that one has to add some capacity if the power system with wind power or thermal power systems should have the same risk of capacity deficit. It must then be noted that the added capacity is only used some hours or less time per year, which means that it has negligible impact on emissions. Since the utilization time is so low it is important, from the cost point of view, not to use base plants for the cost estimates, but instead Open Cycle Gas Turbines or Demand Side Management. This means that the “capacity cost”, or the cost of added capacity to keep the same risk of capacity deficit, is comparatively small, in the range of 2–4 Euro/MWh for the wind power produced (Söder & Amelin, 2008).

5.1.1 Chronological Reliability Models

Capacity value is a probabilistic value that is derived from system observation in the time domain using several time series that include load, wind generation, and conventional generator capability. The different ways of transition from the chronological values to frequency distributions provide an essential distinction between approaches for the calculation of capacity value.

In the time-step or chronological simulation approach the hourly or 15 min values of the total wind power generation are subtracted from hourly or 15 min load data and the residual power is assigned to the available conventional generation units by a scheduling or reliability model, e.g. the ‘National Grid model’ (Giebel, 2000). The chronological approach requires:

1. correct load time series for the period of investigation
2. unbiased wind power time-series for the same period as the loads
3. a complete inventory of conventional generation units’ capacity and forced outage rates
4. target reliability level.

Recent work in the U.S. has utilized high-quality wind data that is from the same time period as the load. This provides the most realistic assessment of wind's contribution to system adequacy if these time-synchronized data series are used as inputs to a chronological reliability model. Wind and load vary from year to year, so it is important to perform a multiyear analysis (ideally a 10–30 year period) using time-synchronized wind and load data if possible. Otherwise, sequential Monte Carlo can be used as long as the Monte Carlo method can retain the diurnal and seasonal characteristics of the wind generation through time. However, in this last case we are loosing part of the fine coincidence between the most stressful peak loads and the wind generation.

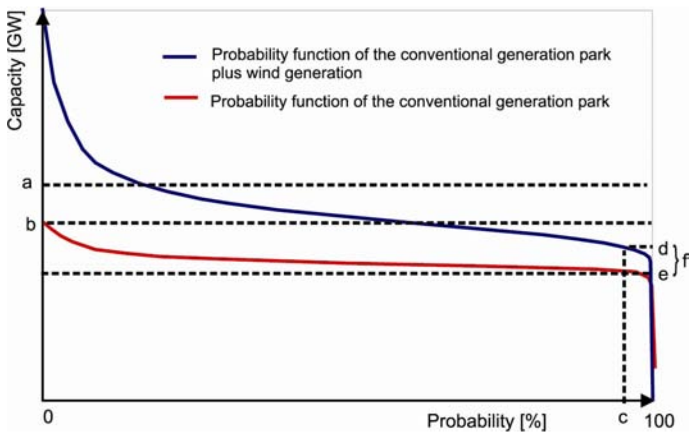
5.1.2 Frequency Distribution Capacity Value Methods

While hourly, time-synchronized load and wind generation profiles for at least ten years are essential prerequisites for wind power capacity value calculations, a number of studies – such as the Dena study - have been exposed to a lack of load profiles for the power system investigated. As an alternative, several of those studies used a frequency distribution representation of wind generation for the capacity value calculation (also called load duration curve method).

The frequency distribution definition of capacity value can be based on firm capacity or equivalent load carrying capacity (ELCC). In this case, the capacity value is obtained by convolving the probability distributions of generating units (wind power and conventional) and the load duration curve. Another approach, which was used in the Dena study, is to base the capacity value only on the probability distribution of the generating units (cf. fig. 34). The approach is however sensitive to the chosen target reliability level, and does not really measure how wind power is contributing to the generation adequacy of the system. Moreover, the Dena method does not consider how the risk of power deficit (LOLP or similar indices) is changed when wind power is added to the system; hence, the Dena method does not measure how wind power is contributing to the generation adequacy of the system. It should also be noted that a capacity value definition based only on generation probability distributions may give significantly different capacity values compared to a definition based on for example ELCC (Amelin, 2008).

The reliable capacity of the system including wind is determined by convolving the wind power probability density function with conventional power plant probabilities. In the studies, (Dena, 2005; Ilex & Strbac, 2002), all installed wind power has been defined as one wind power 'unit'. In order to determine the power probability function of this aggregated 'wind power block', it is again assumed that long-term statistics on wind power availability deliver its probability to be available during hours of significant system risk (high LOLP or equivalent). Reliability models look for periods of time with significant risk. To ensure that no human bias is involved, it is recommended that specific hours or days should not be pre-screened to use for the analysis.

The capacity value is calculated as the difference between the two reliability curves at the target risk level: the power system without and with wind energy. Fig 40 shows how the conventional (thermal and large hydro) generation capacity varies with the target risk level, when taking into account the probabilities arising from technical availability for power generation. In the figure, *c* denotes the reliability target, the red line is the reliability curve without wind, and the blue line is the reliability curve with wind. The distance between points *d* and *e* is the capacity value of the wind generation.



a: installed conventional generation capacity	c: level of supply security	e: guaranteed capacity of conventional generation according to level of supply security
b: available conventional generation capacity	d: guaranteed capacity of combined wind and conventional generation according to level of supply security	f: guaranteed capacity of wind power = 'capacity value'

Fig 40. Dependency of wind power capacity credit on the probability of 'guaranteed capacity' (based on Dena study figure (Dena, 2005)).

The frequency distribution approach immediately converts wind power time series into probability density of power levels, to be combined with the probabilities of conventional power stations' availabilities. A main reason to apply this approach can be the lack of appropriate chronological data. However, the frequency distribution approach will not be informed by variability of wind generation and is not as accurate as the chronological approach, unless net load frequency distributions can be used that take into account the correlation of wind and load. The frequency distribution approach requires:

1. correct load time series for the period of investigation
2. wind power probability density, varying by month or season that can accurately represent the same period as the loads
3. a complete inventory of conventional generation units' capacity and forced outage rates
4. target reliability level.

If a frequency distribution representation of wind generation is used it should be consistent with the load year(s) used in the analysis. An analysis that uses wind and load data from different years can yield invalid results. Many reliability models have the capability to perform Monte Carlo analysis, in which random states of the conventional generation are sampled repeatedly. Even though this is computationally expensive, it can be valuable to more accurately assess the risk of alternative system states. However, the intrinsic Monte Carlo ability that is provided by most, if not all, reliability models may be inadequate for wind because of the more complex probabilistic structure of wind power generation. The challenge for the Monte Carlo simulation, or for any method, is to correctly represent the correlation between wind power production and load variation. Especially if the load peak is very sharp (i.e. few hours per year with an extra high load) it is significantly important to represent the wind power production distribution during these situations in order to obtain a correct value of wind power capacity credit.

5.1.3 Alternative Methods

Because of the relatively intense calculation and data requirements for a reliability assessment of wind capacity value, some approximation methods have been developed. Although reliability-based approaches (including new methods recently developed, and new ones that may appear) appear to be the most robust methods of assessing wind capacity value, there has been considerable interest in developing simpler methods that can be applied on abbreviated data sets. This appears to be more prevalent in the United States. Simplified methods are generally based on wind capacity factor that is calculated over a suitably-defined peak period. The advantage of this approach is that the metric is transparent, and is easy to understand and to relate to system conditions. The first disadvantage of these methods is that they are not capable of taking into account the fine coincidence between the most stressful peak hours and the wind generation. The second disadvantage is that they are not capable of assessing and finding times that the system may be at risk even though loads are not especially high. If a significant fraction of the generating capacity is on maintenance during the shoulder seasons, this can cause a potentially large increase in LOLP, LOLE or LOEE and can result in potentially non-negligible risk outside the peak periods.

There is also emerging interest in reliability-based approaches that differ from LOLP-based methods. Rather than look at LOLP, it may be useful to examine state transition probabilities, focusing on the likelihood that the system will evolve into a state that requires additional balancing or other operator action that arises because of wind (Doherty & O'Malley 2005). More work is anticipated in this area, and as the experience with wind grows around the world, international collaboration will move the state of the art forward.

5.1.4 IEEE Working Group

In 2007 the IEEE Power and Energy Society (PES) through the Wind Power Coordinating Committee set up a working group on Capacity Value of Wind Generation. The group held a meeting at the IEEE PES annual meeting in Pittsburg in July 2008 and hosted a panel session that was well supported. The working group is now preparing a paper on the topic that will be ready in early 2009. The main points that have emerged from the discussions so far are:

- The availability of high quality chronological synchronized data that captures the correlation with load data is of paramount importance and the robustness of the calculations is highly dependent on the volume of this data.

- Approximations should be avoided and a full effective load carrying capability (ELCC) calculation is the preferred method and great care and attention is needed when approximations are used. It is challenging to compare capacity credits performed in different studies if different definitions are used. (Söder & Amelin, 2008; Amelin, 2008.)

- In some reports the term “capacity cost” is used. The meaning of this is the cost for the difference between capacity credit for wind power and capacity credit for a conventional power plant. It is then important to consider the cheapest possible compensation in order not to overestimate this cost. (Söder & Amelin, 2008.)

5.2 Germany

Capacity credit: The increase in (statistically) guaranteed capacity provided by wind power – the capacity in the conventional power plant system which can be completely given up without restricting supply reliability – is between 6 and 8 % in the case of an installed wind power capacity of around 14.5 GW (in 2003) and between 5 and 6 % in the case of an installed wind power capacity of around 36 GW (in 2015), at a level of supply reliability of 99 %.

The selection of the period for the derivation of the probability function of wind turbine feed-in is an important factor. Optimally, the times at which the annual peak load actually occurred should be used for the derivation of the probability function of wind turbine feed-in. From 1994 to 2002 the annual peak load occured in the late hours of the afternoon on days in November or December. To ensure the accuracy of the results, sensitivity calculations were carried out for all winter days (November, December, January and February). The maximum positive or negative deviations of the individual sensitivity calculations from the mean value are approximately +1 % or -1.5 % for 2003 and drop to under +0.5 % or -0.7 % for 2015 (Fig 41). These differences can be regarded as marginal and have no major bearing on subsequent calculations.

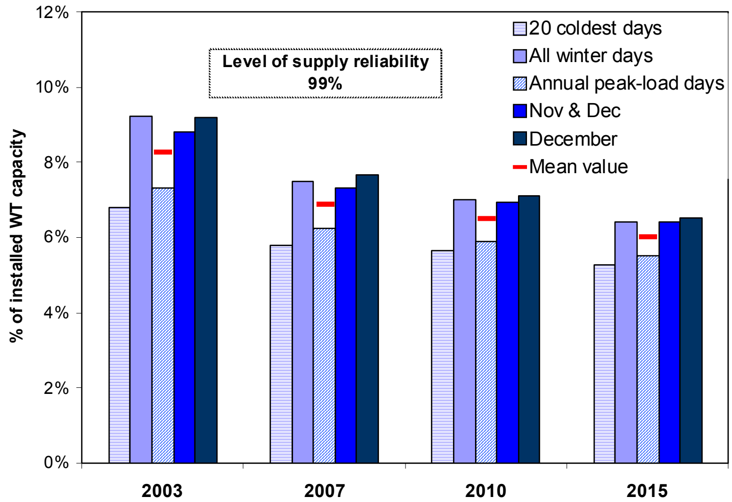


Fig 41. Average gain in secured capacity of the wind turbines in % of the installed WT capacity at the time of the annual peak load (Dena, 2005).

The additionally secured capacity which can be assigned to the installed wind turbines depends on the level of supply reliability. To analyse the influence of this factor, sensitivity calculations were conducted with a level of supply reliability of 97 %, 98 % and 99 %. The selected level of supply reliability influences the values for the specific secured capacity of wind turbines at the time of the annual peak load only slightly (see Fig 42).

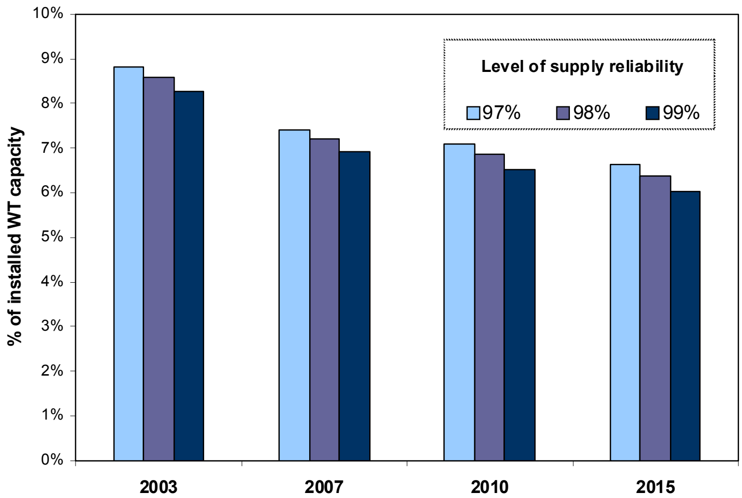


Fig 42. Sensitivities to rises in secured capacity of wind turbines at the time of the annual peak load in relation to the level of supply reliability (Dena, 2005).

The level of the secured capacity of the wind tubines varies seasonally. It is the highest in spring and winter, and in summer it is distinctly below these values (see following table).

Table 18. Seasonal rise in secured capacity of wind turbines (Dena, 2005).

	2003	**2007**	**2010**	**2015**
	% of installed wind turbine capacity			
Winter	8,3 %	6,9 %	6,5 %	6,0 %
Spring	8,6 %	7,2 %	6,9 %	6,4 %
Summer	6,1 %	5,3 %	5,4 %	5,1 %
Autumn	7,2 %	6,1 %	5,9 %	5,5 %
	in MW			
Winter	1.199	1.542	1.941	2.163
Spring	1.245	1.605	2.057	2.289
Summer	889	1.187	1.599	1.824
Autumn	1.040	1.352	1.750	1.970

Methodology: The secured capacity of the entire generation system is determined by using a model in several steps. In the first step the secured capacity of the thermal generation system is determined; in the second step the secured capacity of the entire generation system including the conventional generation system and the dispersed wind power generation system is determined. Dispersed wind power generation includes all wind turbines installed onshore and offshore taking into account their spatial distribution.

The probability and level of outage of thermal generating capacity is determined by an analytical derivation based on the outage probabilities of the single generating units using the recursive convolution method known from probability calculus.

Assumptions: The probability function of the seasonal feed-in of the dispersed wind power generation system is based on quarter-hour feed-in values for the forecast years 2003, 2007, 2010 und 2015. For winter not only the probability function for the entire period (November to February) is determined, but also probability functions for other periods – days when historically annual peak loads were reached, 20 coldest days, days in November and December as well as days in December – are determined.

Assumptions about unplanned outages are differentiated according to the technology involved. They range from 1.8 to 4 % (see following table). An unplanned outage of 0 % is assumed for storage head installations and pumped storage power stations.

Heat controlled combined heat and power plants, run-of-river power stations as well as other electricity options based on renewable energy sources (except wind) are not included endogenously in the model because they are given a secured capacity according to the average feed-in during peak load hours.

A level of supply reliability of 99 % is assumed for further calculations. Levels of supply reliability between 97 % and 99 % are used for sensitivity calculations.

It is assumed that the peak-load case occurs in the winter and without significant wind power feed-in. The peak-load is assumed to be constant over the long term. Depending on the grid region, the peak load can occur up to 800 hours a year.

Table 19. Outage rates for power plants (Dena, 2005).

Power plant technologies	**Unplanned, non-disposable outages**
Nuclear power stations	3,0 %
Lignite fired power stations	3,2 %
Hard coal fired power stations	3,8 %
Natural gas and steam fired power plants	1,8 %
Gas fired steam turbine	1,8 %
Gas turbines	3,0 %
Oil fired power station	1,8 %
Storgage power station	0,0 %
Pumped storage hydro power stations	0,0 %

Limitations: No additional measures to raise the level of the secured capacity of wind tubines like storage systems or extended power exchange over large areas with different weather conditions (European smoothing effects) were assumed in this study.

5.3 Ireland/ESBNG

The transmission system operator of the Republic of Ireland, ESB National Grid (now EirGrid), published a report in 2004 (ESBNG, 2004). The objective of this study was to analyse and quantify the impact of increasing levels of Wind Power on operation of conventional plant in the Republic of Ireland, and calculate the capacity credit of wind power on the system.

Results: The study found that a high wind energy penetration greatly increased the number of start ups and ramping for gas turbine generation in the system and that the cost of using wind power for CO_2 abatement in the Irish electricity system is €120/Tonne. The capacity credit for different levels of wind is shown in Fig 43.

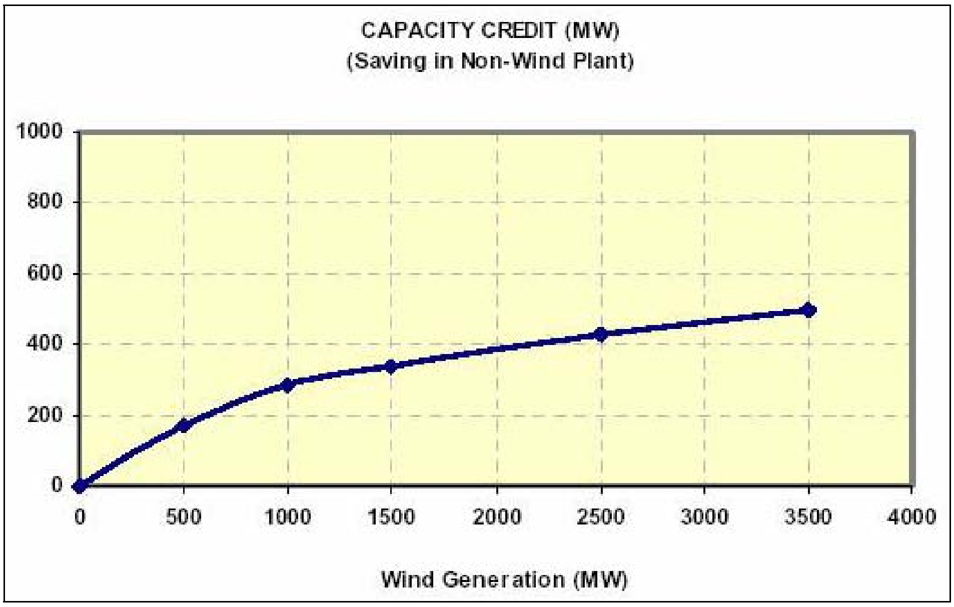


Fig 43. Results for capacity credit of wind power for Ireland (ESBNG, 2004).

Input data, wind power modelling: The wind input assessment methodology used was direct scaling of output data from existing wind power production combined with some planned site wind data to create a power time series.

Methodology: Capacity credit was calculated by assessing the amount of conventional thermal plant that may be removed to maintain the adequacy at the desired level. The system assessment methodology was generating system simulation using a unit commitment and dispatch simulator. Two scenarios were examined – one with a peak load of 5000MW and one with a peak load of 6 500MW. For each scenario, 4 different levels of installed wind power were examined. Review matrix is in Appendix 2.

Assumptions: Diverse wind power plant locations were assumed, including an assumption that 33 % of wind power capacity is offshore. It was assumed wind power can be forecast with a high degree of accuracy.

5.4 Norway

The impact of wind power on system adequacy for one region in Norway was reported in (Tande and Korpås, 2006). The impact is assessed using data from a real life regional hydro-based power system with a predicted need for new generation and/or reinforcement of interconnections to meet future demand (Fig 44).

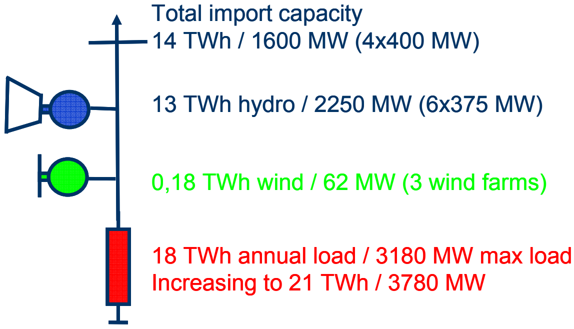


Fig 44. Assumed case study system specifications.

Methodology: The loss of load probability LOLP = Pr (Pm < 0) is calculated by using standard statistical methods as briefly described below. Here, the generating capacity margin Pm is the difference between the available conventional capacity Pc and the net load Pn.

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

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

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

Results: Wind power will have a positive effect on system adequacy. Wind power contributes to reducing the LOLP and to improving the energy balance. Adding 3 TWh of wind or 3 TWh of gas generation are found to contribute equally to the energy balance, both on a weekly and annual basis. Both wind and gas improves the power balance. The capacity value of gas is found to be about 95 % of rated, and the capacity value of wind about 30 % at low wind energy penetration and about 14 % at 15 % penetration. The smoothing effect due to geographical distribution of wind power has a significant impact on the wind capacity value at high penetration.

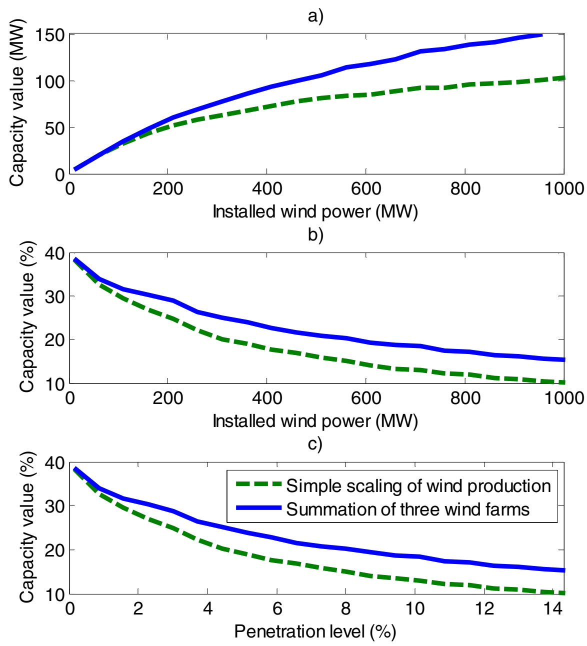


Fig 45. Capacity value of wind power with and without geographical smoothing effect. a) Capacity value in MW. b) Capacity value in percentage of installed wind power. c) Capacity value as a function of wind penetration level.

5.5 UK

5.5.1 Ilex/Strbac, 2002

The current electricity market does not contain a statutory or formal generation security standard that would define the required capacity margin for a particular mix of generation types. To make an explicit calculation, the last security standard employed in the UK was taken as indicative of the security of supply that would be acceptable. Assuming no increase in loss of supply risk (chance of needing to interrupt supplies not being more that nine winters in one hundred, i.e. a 9 % risk), the amount of conventional generation that can be displaced by wind generation was evaluated.

Results: For a small level of wind penetration the capacity value of wind is roughly equal to its load factor, approximately 35 %. But as the capacity of wind generation increases, the marginal contribution declines. For the level of wind penetration of 20 GW, about 4GW of conventional capacity could be displaced, giving a capacity credit of about 20 %.

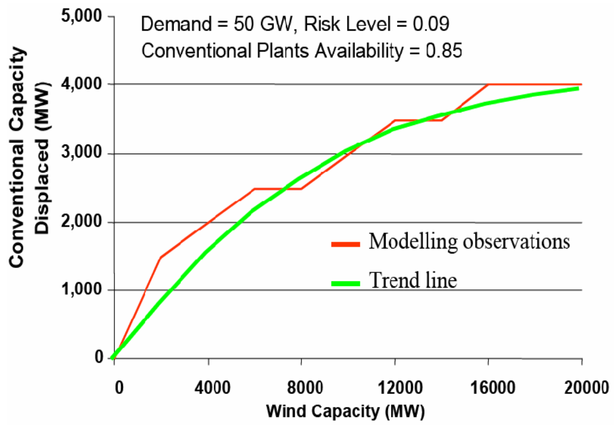


Figure 46. Capacity of conventional plant that can be displaced by wind generation.

Input data, wind power modeling: Annual half-hourly profiles of wind output based on historic wind generation data were developed. These one-year time series for various levels of wind penetration in the system depicted different levels of wind diversity. For the purposes of assessing capacity credit, the typical distribution of wind output seen in the various time series available is also expected to occur during high demand conditions.

Limitations: As this study was based on a one-year tme series of wind generation data (for which a consistent set of data was available), extreme conditions of the coincidence of very high demand and little or no wind may not be captured. The reliability criterion LOLP applied in establishing the capacity contribution of wind in this study, only provides a simplified comparison of the reliability of prospective generation systems as it does not provide any indication of the frequency, duration and the severity of potential shortages. Impact of extreme weather conditions, widespread anticyclones and storms (taking into consideration effects of clustering) were also not analysed. These factors have been identified as an imperative area of further work relevant to future electric system development in the UK. Furthermore, the impacts of supply interruptions on electricity consumers are an important factor in the determination of acceptable and economically justifiable service reliability levels and on the investments required to attain and sustain these levels. The information about frequency, duration and severity of supply interruptions is vital for assessing the opportunities for alternatives such as; demand side and bulk storage systems, in providing cost effective solutions to integration of wind power.

Also the approach used in this study to quantify additional system capacity costs attributed to wind generation were relatively simple and more advanced methodologies are being developed.

5.5.2 Strbac et al., 2007

This study has also applied one of the conventional techniques, that quantifies the probability that peak demand will exceed available generation, to determine the capacity credit of wind power. However, these approaches neither give any indication of the frequency of the occurrences of insufficient capacity conditions, nor the duration for which they are likely to exist. Furthermore, the severity of shortages, in terms of power and energy is not quantified (only the probability of a single shortage occurring). The information about the frequency, duration and magnitudes of various potential deficits is necessary to establish if bulk energy storage facilities or demand side management options are to be considered as an alternative to conventional plants as backup for wind generation. In order to determine the risk of supply interruptions at various levels of wind penetration, the frequency and duration method (FDM) was applied in this study.

Results: For the calculation of the capacity value of wind generation in UK, profiles with two different diversity levels were created. Fig 47 shows the results of analysis carried out for a range of wind penetrations to examine the generating capacity of conventional plant that can be displaced by wind while maintaining the risk of loss of supply at the historical level of 9 %, for a 70GW peak load and a 400TWh energy demand, and a 35 % load factor of wind.

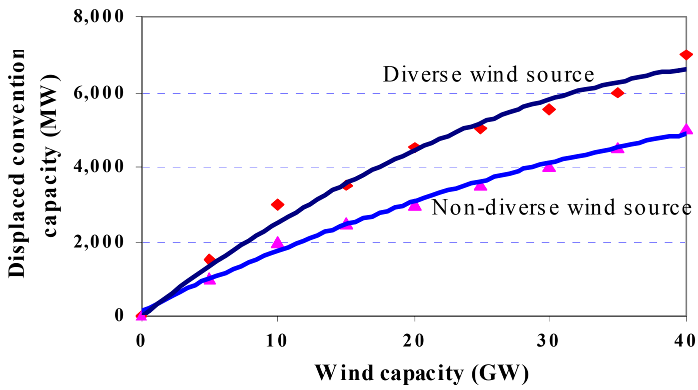


Fig 47. Conventional capacity displacement by diverse and non-diverse wind resource.

By applying the frequency and duration FDM approach it was investigated how various extents of wind penetration affect the frequency and duration of potential capacity deficits. A comparison of this is made with a system having no variable source. The results are presented in Fig 48.

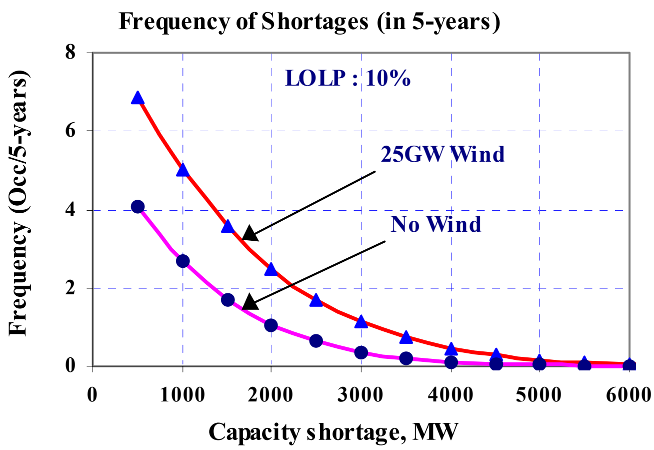


Fig 48. Frequency of interruptions at various magnitudes of shortages in systems with and without wind.

Methodology: The reliability index called loss of load probability (LOLP) was used to measure the adequacy of the generation system and determine the amount of plant necessary to meet the demand at an adequate level of security. This index quantifies the probability of peak load exceeding available generation (i.e. probability of a shortage). The conventional units are characterised by their long-term behaviour in terms of their average failure and repair cycles and this defines their average availabilities. The total wind capacity is represented in the system as a multistate unit.

In order to determine the risk of supply interruptions using the frequency and duration method FDM the generation system model (conventional as well as wind) was based upon a Markov chain model. The generation capacity states are combined with the load statistics to compute data on the probability and frequency of occurrence of various reserve margin states. A negative margin state indicates that the system load exceeds available capacity and depicts a loss of supply situation.

5.6 Portugal and Spain

Project RESERVAS involved INESC Porto (a R&D institute) and the System Operators of Portugal (REN) and Spain (REE), within their joint medium and long term planning activities related to MIBEL (the Iberian electricity market). In developing the project, INESC Porto had the support of Universidade de Itajubá (Brazil) and worked in close collaboration with REN and REE teams that were responsible for the specification of the project objectives, model approval and analysis of the results. The project was dedicated to the evaluation of the risk associated with specific future configurations of the two generating systems, until the horizon of 2025, to allow a large scale integration of variable renewable sources, with a particular emphasis in wind energy.

Methodology: a new approach for long-term operating reserve adequacy evaluation was developed and tested. Chronological Monte Carlo simulation was used to evaluate the adequacy of the generation capacity and of the operating reserves (reserve needed for one hour ahead), taking into account unit's failures, the availability of hydro, wind power, cogeneration, PV and other renewables and unexpected wind power and load variations. Chronological simulation preserves the complex interactions between the different aspects that influence the risk associated to the generating systems.

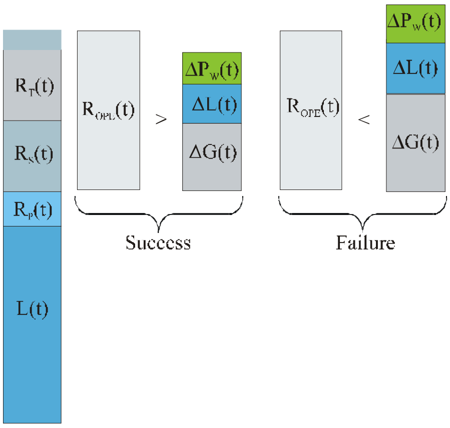
The algorithm starts by defining, for each simulation of a specific year, the hourly load to be served by the system, and draw (from an historical database) the series of hourly wind availability and of monthly hydro volumes that are used to estimate hydro power available capacity. CHP and the remaining generation in special regime (biomass, biogas, solid waste and industrial waste) are also considered, and maintenance is assigned to the chronological periods where it is expected to occur. Over this chronological frame that preserves the correlations between load, maintenance, wind and hydro, the times to failure and repair times of each individual generator are sampled, according to their statistical distributions and specific parameters (failure rate and mean repair time).

This defines a number of success states, where the available power is sufficient to meet the load, and failure states that result from the unavailability of generation, due to the units' failures or lack of natural resources, in a way that load cannot be supplied. In each failure state power not supplied is calculated, and chronology is again used to retain information about the duration of the failure event. Repeating the simulation for a significant number of years produces statistics of these indicators that lead to the performance indices.

Well-Being Analysis provides additional characterization of the performance of the power system, by splitting the success states into healthy and marginal states, depending on whether or not a deterministic rule for reserve is satisfied. The specified value for secondary reserve, or the largest available units in the system, are typical thresholds used for this purpose. In the first case, for instance, the state is considered healthy if the margin between available generation and load is greater than the required secondary reserve. Well-being analysis provides the following useful indices:

- EH – expected healthy hours, which is the expected number of hours in a period (e.g. year) the system will stay in healthy states (h/yr)
- EM – expected marginal hours, which is the expected number of hours in a period (e.g. year) the system will stay in marginal states (h/yr)
- FH, FM – expected frequency associated with healthy and marginal states, respectively (yr-1)
- DH, DM – expected duration of system residing in healthy and marginal states, respectively (h)

One of the significant features of the project consisted on the evaluation of the operating reserve. Due to the characteristics of the two power systems of Portugal and Spain, the operating reserve is formed by a not very large secondary reserve and a significant amount of fast tertiary reserve (mainly hydro). In the framework of reliability studies, it is checked whether or not the existing units will be sufficient to deliver the reserve when the needs come, that is, if the existing units would be enough to provide the necessary capacity when confronted with unexpected wind and load variations and outages (Fig 49).



Variables:

L(t)	Load at period *t*
R_P(t)	Primary Reserve at period *t*
R_S(t)	Secondary Reserve at period *t*
R_T(t)	Tertiary Reserve available in less than 1 hour at period *t*
R_{OPE}(t)	Operational Reserve at period *t*
ΔG(t)	Loss of generation in period *t*
ΔL(t)	Unexpected load variation in period *t*
ΔP_w(t)	Unexpected wind power variation in period *t*

Fig 49. Operating Reserve Adequacy concept.

In period *t* a minimum number units will have to be dispatched to satisfy the forecasted load and the specified needs for primary and secondary reserve. Moreover, in order to complete the operating reserve, units that could be available in less than one hour must be identified. The extra amount of capacity at the top of the tertiary reserve shown in the figure is due to the discrete nature of unit generating capacities.

Although the project was not aimed at estimating the capacity credit, its risk assessment methodology can be used to estimate the capacity credit of a certain amount of new wind power, by decreasing the number of thermal units until the level of risk is the same than before the addition of the new wind power. Since the methodology calculates not only the general adequacy of the generating system but also the risk associated to the operating reserve, we probably would find two different values for the capacity credit of a specific system, due to the different impacts of wind power in the global generating capacity and in the operating reserve needs.

Input data, wind power: Portugal was divided into 7 regions and Spain into 18 regions. The studies were developed not only for the base scenario of each year, where all the hydro and wind series were equally probable, but also for more stressing scenarios corresponding to the worst hydrologic condition (H-), or to the conjunction of this condition with reduced wind power and increased maintenance (HWM). A scenario with the most wet hydrologic condition series (H+) was also simulated. In order to model the variability of hydro availability, 16 years of monthly hydrological conditions were used (1990–2005).

Results: For Portugal (and Spain, separately) the following indices were calculated:

- Classical reliability indices (LOLP; LOLE; Expected Energy Not Supplied EENS, etc.) for system adequacy.
- Well-being indices.
- Reliability indices for the operating reserve (LOLP, etc.). This included not only the base case for each system, but also different scenarios for dry years, reduced wind availability, etc. In the additional studies, specific risk indices were calculated (e.g. expected wasted renewable energy).

Results for the LOLE are presented in Fig 50 and Fig 51. Note that the configuration of the system changes from year to year, with new units being added and others being removed. Also, installed wind power has changed from year to year (increasing) and load increased from year to year.

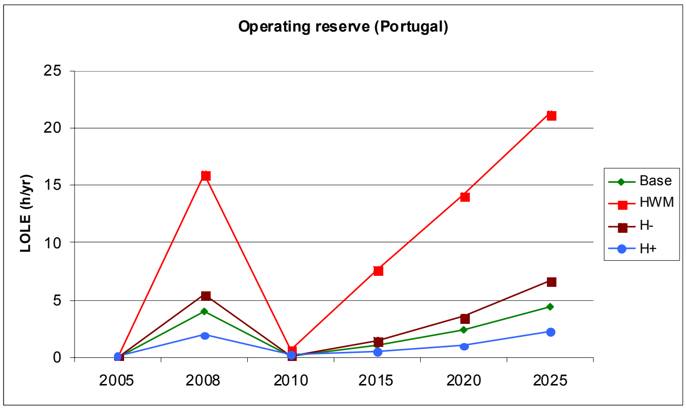


Fig 50. Estimated Loss of Load Expectation (LOLE) due to operating reserve insufficiency, for some of the scenarios considered in the study for Portugal.

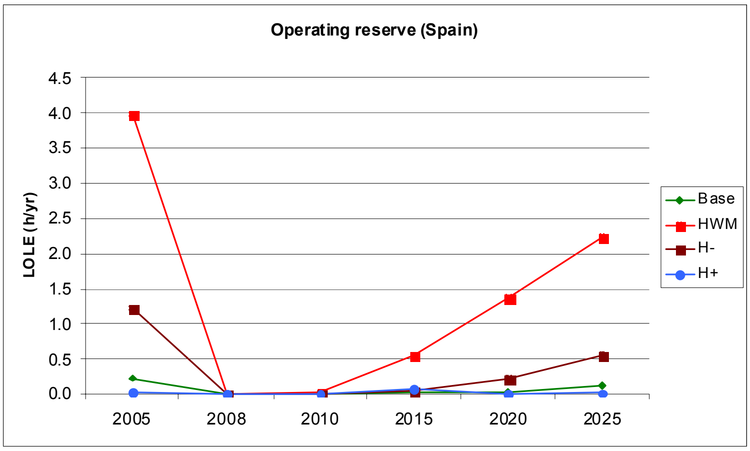


Fig 51. estimated Loss of Load Expectation (LOLE) due to operating reserve insufficiency, for some of the scenarios considered in the study for Spain.

An important feature of the simulation tool is its ability to calculate monthly values of the risk indices. The next figure shows an example for Portugal, where the concentration of the risk in some months is evident.

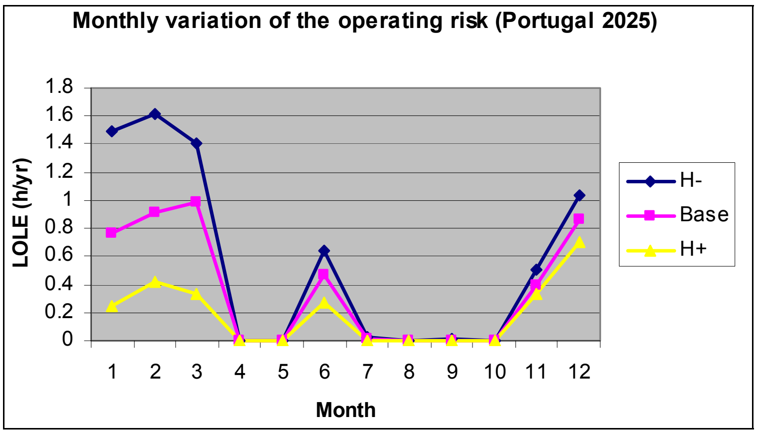


Fig 52. Monthly variation of risk.

Additional results about the impact of interconnections, risk of wasting renewable energy in valley hours and influence of new units and new pumping storage in the reserve were also produced. In addition to the common reliability indices (LOLP, LOLE, ELCC) the probability distributions of the random variables that are behind the average values were obtained. This gives more insight to the risk than just the mean value. For instance, in this case (Fig 53), it can be seen that the most probable situation (61.8 % probability) corresponds to a negligible loss of load, but there is almost 10 % probability of having a loss of load of around 3 h/yr, and more than 1.5 % probability of a loss of load greater than 6 h/yr.

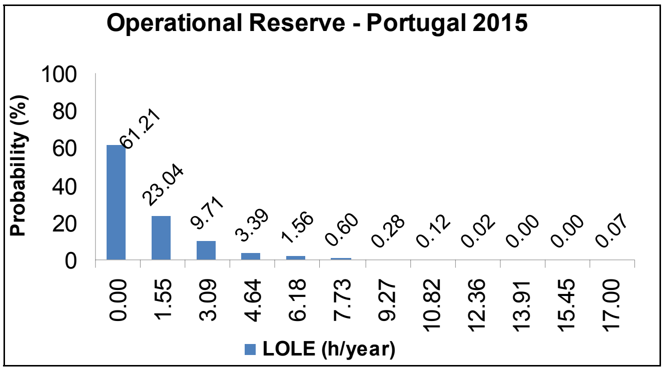


Fig 53. The probability distribution for operational reserve adequacy in 2015, in Portugal.

Note that, even if the direct capacity credit values calculation was not an objective of the project, the simulation tool can be used to perform that kind of evaluation, e.g. finding by trail and error the thermal capacity that could substitute variable generation, while maintaining the risk level.

5.7 USA

There is no uniformly accepted method for calculating the capacity value of wind plants in the US. Effective load carrying capability (ELCC) is generally accepted as the “gold standard” for determining capacity value of wind plant. ELCC of wind generation can vary significantly, and depends primarily on the timing of the wind energy delivery relative to times of high system risk (defined as loss of load probability or similar metric). The capacity value of wind plants has been shown to range from approximately 5 %–40 % of the wind plant rated capacity. Table 20 (Milligan & Porter, 2008.) shows the variety of methods being used in different regions of the US, and some of the results obtained. In some cases, simplified methods are used to approximate the rigorous reliability analysis.

The Minnesota Dept. of Commerce/Enernex Study described in 3.11.1 estimated the impact of wind in a 2010 scenario of 1500 MW of wind in a 10 GW peak load system. A capacity credit of 26 %–34 % was found with a range of assumptions using the ELCC method. Updated study was made for wind penetration of 25 % energy from wind to the load in the whole state of Minnesota, assuming a well-developed market operating in the territory of MISO, the Midwest Independent System Operator (see also section 3.11.2). The capacity value of the wind generation was subject to substantial inter-annual variability, ranging from a low of 5 % of installed capacity to over 20 %.

Two recent studies in the U.S. attempted to calculate multi-year capacity value for wind (Milligan & Porter, 2008). ERCOT sampled from a long-term database of wind speeds and power, and calculated ELCC from the samples. This approach therefore used load and wind that is not time-synchronized, resulting in questionable results. Xcel Colorado used a 10-year wind data set from a numerical weather prediction model. Although the time synchronization was nominally preserved, the method used for load forecasting may have compromised the results somewhat.

Simplified methods based on wind capacity factor over peak period have been used in several studies. PJM, a Regional Transmission Operator (RTO) in the north-eastern section of the US, considers the peak period to be in the hours ending 3:00–7:00 PM during June, July, and August. The wind capacity value is therefore calculated as the capacity factor achieved by wind in this time period. To help account for inter-annual variations, PJM prescribes the use of a 3-year rolling average that is based on the most recent 3-year period during the peak period. Studies done in New York and California found that similar approaches did a reasonably good job of approximating the ELCC, based on the regional definitions of peak periods. The Mid-Continent Area Power Pool (MAPP) uses a similar method, but instead of calculating the capacity factor, MAPP prescribes the use of the median wind generation value in a 4-hour window that includes the monthly system peak. Up to ten years of data can be used if available. The Southwest Area Power Pool (SPP) uses a similar approach, but uses the 85 percentile of wind generation instead of the 50 % percentile (median) that is used by MAPP. The SPP approach is shown to be extremely conservative by Milligan & Porter (2005).

For California, a wind capacity credit of 23 %–25 % of a benchmark gas unit was found.

PacifiCorp determined the capacity value for wind resources on its system by using a probabilistic reliability assessment technique in the 2005 IRP. The wind power plant average contribution to capacity value was 21 %. Due to the results of this study with its conservative performance assumptions, PacifiCorp adopted a 20 % capacity contribution toward the planning reserve margin for wind resources, which was a change from the 0 % capacity contribution assumption used in the 2003 IRP.

Table 20. Wind Capacity Value in the U.S (Milligan & Porter, 2008).

Region/ Utility	Method	Note
CA/CEC	ELCC	Rank bid evaluations for RPS (mid 20s); 3-year near-match capacity factor for peak period used by CA PUC and CA ISO.
CPUC	Peak Period	Three-year rolling average of the monthly average of wind energy generation between 12 and 6 p.m. for the months of May through September.
PJM	Peak Period	Jun-Aug HE 3 p.m. – 7 p.m., local time, capacity factor using 3-year rolling average (13 %, fold in actual data when available).
MN 20 % Study	ELCC	Found significant variation in ELCC: 4 %, 15 %, 25 % and variation based on year.
ERCOT	ELCC	ELCC based on random wind data, compromising correlation between wind and load (8.7 %).
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26–34 %).
NY ISO	Peak Period	Wind's capacity factor between 2–6 p.m., June through August, and 4–8 p.m., December through February.
CO PUC/Xcel	ELCC	12.5 % of rated capacity based on 10-year ELCC study. Load forecast algorithm compromised correlation between wind and load.
PacifiCorp	ELCC	Sequential Monte Carlo (20 %). Z-method 2006.
MAPP	Peak Period	Monthly 4-hour window, median.
Idaho Power	Peak Period	4 p.m. – 8 p.m. capacity factor during July (5 %).
Nebraska Public Power District		17 % (method not stated).
Northwest Resource Adequacy Forum	Rule of Thumb	15 %. Being studied further for potential revision.

Tri-State	Peak Period	2–12 %. Appears to be based on wind's contribution to monthly coincidental peak.
SPP	Peak Period	Top 10 % loads/month; 85th percentile.
PNM	Peak Period	Capacity factor between 4–5 p.m. in July.
ISO New England	Peak Period	For existing wind: wind's capacity factor between 2–6 p.m., June through September and 6–7 p.m. from October through May. For new wind: based on summer and winter wind speed data, subject to verification by ISO New England and adjusted by operating experience.

CA/CEC: California/California Energy Commission
CPUC: California Public Utilities Commission
MN 20 % Study was sponsored by the Minnesota Public Utilities Commission
RPS: Renewable Portfolio Standard
ELCC: Effective load-carrying capability – capacity value based on reliability metric
PJM: Pennsylvania-Jersey-Maryland, an RTO (regional transmission organization) in the US
HE: Hours ending
ERCOT: Electric Reliability Council of Texas
MN/DOC: Minnesota Department of Commerce, the sponsor of the Xcel Wind Integration Study
GE/NYSERDA: General Electric Energy Consulting, New York State Energy Research Development Authority
CO PUC: Colorado Public Utilities Commission
MAPP: Mid-Continent Area Power Pool
RMATS: Rocky Mountain Area Transmission Study
PGE: Portland General Electric
PSE: Puget Sound Energy
CF: Capacity factor
SPP: Southwest Area Power Pool
PNM: Public Service Company of New Mexico

5.8 Europe Tradewind

Tradewind (Van Hulle et al., 2009) used the European wind power time series to calculate the effect of geographical aggregation on the contribution of wind power to generation adequacy.

It was found that averaged over the whole of Europe wind power generation is 1.2 times higher than average during peak load hours. The countries studied by TradeWind show an average wind power capacity factor of 30–40 % during the 100 highest peak load situations for the 2020 Medium scenarios. The average European capacity factor is strongly determined by the wind power capacities in Germany and France.

Alongside this correlation of power demand and wind power output, and its positive effect on the capacity credit, a probabilistic capacity credit calculation (same as in German Dena study) looked into the effect aggregating wind power from larger areas has on the capacity credit. The results for the 2020 Medium scenario (200 GW) show that aggregating wind energy production from multiple countries strongly increases the capacity credit and the greater geographic area the grouped countries represent, the higher is the capacity credit. If no wind energy is exchanged between the European countries, the capacity credit in Europe is on average 8 %, which corresponds to 16 GW. When Europe is calculated as one wind energy production system and wind energy is distributed across multiple countries according to individual load profiles, the capacity credit almost almost doubles to 14 %, which corresponds approximately to 27 GW of firm power in the system.

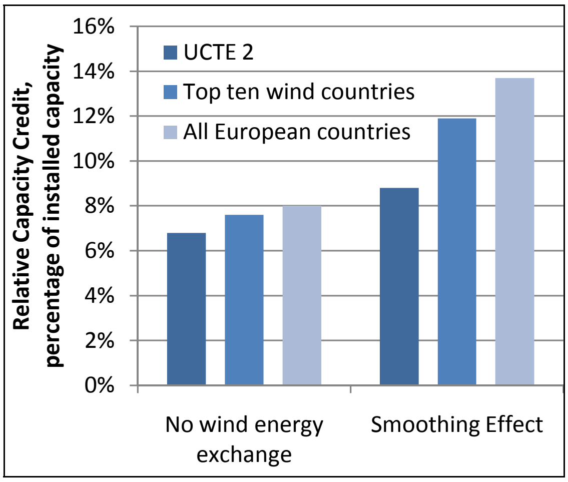


Fig 54. Increase in capacity credit when aggregating larger areas of wind power. (Source: Van Hulle et al., 2009.)

6. Experience from operating power systems with large amounts of wind power

Even if wind power penetration is still rather limited in most countries and power systems, already some regions show a high penetration and have first practical experience from wind integration. Here experience from regions where wind power production is more than 20 % of gross demand is reported: West Denmark (24 %), North of Germany (33 %), certain Spanish regions (Navarra 44 %, Castilla-La Mancha 40 %, Aragón 37 %, Galicia 34 % and Castilla y León 32 %) and Gotland in Sweden (20 %) (Table 21).

Table 21. Regions with high penetration level of wind power.

Region	Load			Intercon-nection	Wind power		Wind power penetration	
	Peak MW	Min MW	TWh/a	MW	MW	TWh/a	% of gross demand	Max wind / (Min load + interconn.)
West Denmark	3 700	1 400	21	2 570 / 3 070	2 350	5	24 %	59 %
North-Germany	2 000	750	12.6	5 200	2 275	4.2	33 %	38 %
Ireland	5 000	1 800	29	500	745	1.6	6 %	32 %
Spain	38 200	15 300	230	1 800–2 800	11 615	23.4	10 %	68 %
Gotland, Sweden	160	45	0.93	180	90	0.18	19 %	40 %

6.1 West Denmark

- Most of the variability of wind can be balanced by using strong HVDC-interconnections especially to Norway and Sweden. The expected wind power production is traded at the Nordpool spot market (day-ahead forecasts) and forecast errors paid by Nordic regulating power market prices (regulating power used according to system net imbalances in Nordel). Estimated costs due to forecast errors day-ahead are between 1.2 and 2.6 €/MWh
- Difficulties when large forecast errors occur that are not foreseen even from updated forecasts. An example has been the storm in January 2005 when 1600 MW were lost within 6 hours, 66 % of the installed wind power capacity. These situations do not occur very often, but the system should be prepared anyhow.
- Surplus production requiring curtailing of wind power has seldomly occurred since 2003. This has partly been due to large amount of distributed local combined heat and power plants that have operated according to fixed tariffs. After enhanced flexibility in CHP production, wind curtailment has not occurred so often. Interconnection capacity to Germany cannot be utilised during high wind periods because surplus wind production in Northern Germany occurs simultaneously.
- No increase in amount of reserve capacity, but increase in use of operating reserves (regulating power 10–15 min). Wind power has contributed to the increase of Automatic Generation Control (AGC), which amounts to 140 MW of regulation capacity from conventional power plants to be able to manage the fast fluctuations (time scale seconds).
- No experience of turbines tripping off in large quantities due to grid faults.

6.2 North-Germany

- The variability of wind is dealt with by the TSOs, sharing the amount of regulation power needed. TSOs tender and purchase adequate control power on the basis of the day-ahead wind power prognosis. The large variations of wind power production especially in storm events pose a major challenge to grid operators. On occasions with large amounts of wind during low load, the interconnections to neighbouring countries (the Netherlands and Poland) are used so much that the neighboring power systems are signigicantly affected.
- Surplus production requiring curtailing of wind power has occurred since mid 2003 in Schleswig-Holstein and since 2005 in Lower Saxony. This is due to grid bottlenecks during windy periods. In order to be in a position to connect further renewable energy generators before the grid expansion is completed, E.ON Netz has developed the so-called generation management as a transitional solution. Generation management involves reduction of the power fed in by the renewable energy generators, in order to protect grid equipment such as overhead lines or transformers from feed-in-related overloads, thereby avoiding supply failures.
- No increase in amount of reserve capacity, but increase in use of operating reserves (regulating power 10–15 min) (Eriksen et al., 2005).
- Faults in the extra-high voltage grid can result in a sudden failing of a large number of wind power plants in the affected region. If 3,000 MW were to fail, grid stability would be put at risk. E.ON Netz published new grid interconnection regulations on 1st April 2006 (http://www.eon-netz.com) requiring fault-ride-through to deal with this problem.

6.3 Ireland

EirGrid has successfully integrated over 1GW of wind power to date. With a stated government target of over 6GW Ireland will shortly have a penetration level comparable to that of West Denmark and is set to become amongst the systems with the greatest wind penetration levels.

Successfully integrating 1GW of wind capacity has involved addressing issues such as:

- Producing new Grid/Distribution Code rules for Wind Farms.
- Processing connections including the development and implementation of the Group Processing Approach for the processing of large numbers of grid-connection applications.
- Constructing connections to the network and associated deep reinforcements.
- Development of operational procedures.
- Wind power forecasting.
- Introduction of wind farm SCADA.
- Assessment of the impact of wind on system economics.
- Assessment of likely levels of curtailment and/or constraint of wind generation.
- System stability assessment including involvement in model development.

These technical activities have been paralleled by significant stakeholder involvement by management and staff. However, despite these achievements the continuing rapid growth of wind generation will require even greater efforts to address the ever-more complex technical, commercial, regulatory and stakeholder issues that will arise.

6.4 Spain

At the end of 2008, installed wind power capacity was about 16 GW (17 % of the total power capacity), with a generated energy of 31.5 TWh (11 % of the total annual demand 264 TWh). The total installed Spanish electricity generation capacity was around 95 GW at the end of 2008. Canary Islands, currently with installed wind power of 142 MW, have fixed a final target of 1025 MW for 2015. The generated energy of this target will exceed the forecasted electricity demand during low demand (valley hours). On April 18, 2008 was set the last daily record of daily wind power production and penetration in the system with 213 GWh, covering the 28.2 % of the electricity demand on that day. The high variability of wind power results in different penetration levels on an hourly basis: on November 24, 2008, 43 % of demand was covered by wind power, while November 27 only 1.15 % of total demand was covered by wind power.

- No increase in amount of reserve capacity, but increase in use of operating reserves (regulating power 10–15 min). (Eriksen et al., 2005.)
- Faults in the extra-high voltage grid can result in a sudden failing of a large number of wind power plants in the affected region, thereby putting the grid stability at risk. As an example, several successive wind power decreases directly provoked by voltage dips occurred at 19 March 2007 during about 6 hours (500 MW, 400 MW and 1000 MW). Before, Spanish requirements established that wind turbines had to disconnect when they were submitted to voltage dips, avoiding so disturbances caused by the operation of the wind turbine under these conditions. New grid codes require fault-ride-through to avoid this problem.
- Curtailing of wind power has occurred due to concern of power system transient stability since 2004 (Eriksen et al., 2005). In the early morning of November 2, 2008, was given an instruction to lower the wind power production to maintain system stability nearly 2800 MW, due to the inability to integrate all the wind for lack of sufficient demand.
- Spanish wind farms owners, and in general power plants based on renewables, have since 2007 set up operation centers for their power plants, some owners also around the globe. Iberdrola Renovables operation center (CORE) is the largest one in Spain. The CORE command center remotely monitors the company´s renewable energy generation assets. It was designed to optimize the renewable facilities´ technical management and economic performance. The generation of the renewable energy producers are currently managed and controlled by CECRE, operation units integrated into the Power Control Centre (Cecoel). The power control centre (Cecoel) is responsible for the coordinated real-time operation and supervision of the generation and transmission facilities of the Spanish electrical system.

  The Cecoel issues the operational instructions of the production and transmission system with the aim of guaranteeing the security and quality of the electrical supply. With this wind power plant management tool, Spain becomes the first country to have all of its wind power plants with a capacity larger than 10 MW connected to a control centre. By the end of February 2008, the system had already 21 generation control centres with 13 154 MW wind power connected to them. This allows replacing hypotheses of local or global simultaneity and preventive criteria with real time control of the production. For that purpose, the GEMAS (Maximum Admissible Wind Power Generation in the System in its Spanish acronym) tool has been designed and developed by the TSO REE. The CECRE sends the maximum production limits calculated in real time by GEMAS. These orders are sent to the control centres which will manage them so that the wind power production is limited to the maximum calculated. The grid condition and its electrical parameters are continuously controlled by the Power Control Centre, with a telecommunications network, which will act on the control variables to uphold the supply security and quality or restore service, when incidents arise. The Power Control Centre is backed up by a state-of-the-art control system, which is intended to manage the real time information received from power plants and the grid facilities.

6.5 Sweden: Gotland

All balancing in the island is done with the HVDC cable to the mainland. When wind power penetration (of gross demand) exceeded 10 % there were occasional curtailments when wind power production was close to the local load and the cable was run near 0 MW. To overcome this problem, control of the cable was enhanced to enable switching to export and import near 0 MW. After this there has not been any need to curtail wind power. From mainland side point of view Gotland wind power production is comparatively small (Söder et al., 2007).

7. Summary and review of the results

Many wind integration studies give estimated impacts as increase in reserve requirements (MW), increase in grid reinforcement needs (kms for different kV lines), and integration costs ($/MWh, €/MWh). Many studies give the results in less comparable ways, like impacts on the scheduling of other power plants and exports, impacts on the stability of the transmission grid, impacts on adequacy of power. Different metrics for the results have been used in the studies: Results as monetary value per MWh of wind or per MWh of total consumption (reflecting the increase in consumer price). There are also results as % of more wind power production needed to cover extra losses.

Integration cost can be divided into different components arising from the increase in the operational balancing cost and grid expansion cost. The value of the capacity credit of wind power can also be stated. Integration costs of wind power need to be compared to something, like the production costs or market value of wind power, or integration cost of other production forms. In most case studies a comparison to other alternatives to wind has not been studied.

When estimating the costs, allocation of new grid or reserve capacity to wind power can differ. For increased balancing it is important to note whether a market cost has been estimated or whether the results refer to technical cost for the power system. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels. The trade-off between curtailing wind output in critical times and providing new transmission or production capacity would be needed in some cases.

In the following graphs only the cost component has been analysed. The case studies summarized are not easy to compare due to different methodology and data used, as well as different assumptions on the interconnection capacity available.

Determining what is "high" penetration of wind power is not straightforward. Often either energy or capacity metrics are used: wind power production as % of gross demand (energy) and wind power as % of peak load (capacity). To determine high penetration for a power system also interconnecting capacity needs to be looked at. This is because critical moments of high wind and low load can be relieved by using interconnector capacity. The power systems and highest wind penetrations presented in the case studies of previous chapters are summarised in Table 4 of Section 2. The same information is presented in Fig 55, where it can be seen that taking into account the limitations of interconnection capacity, the penetration levels of Ireland and UK are more challenging than for the other European countries. The on-going studies that have not been taken in this report are listed in Appendix 1.

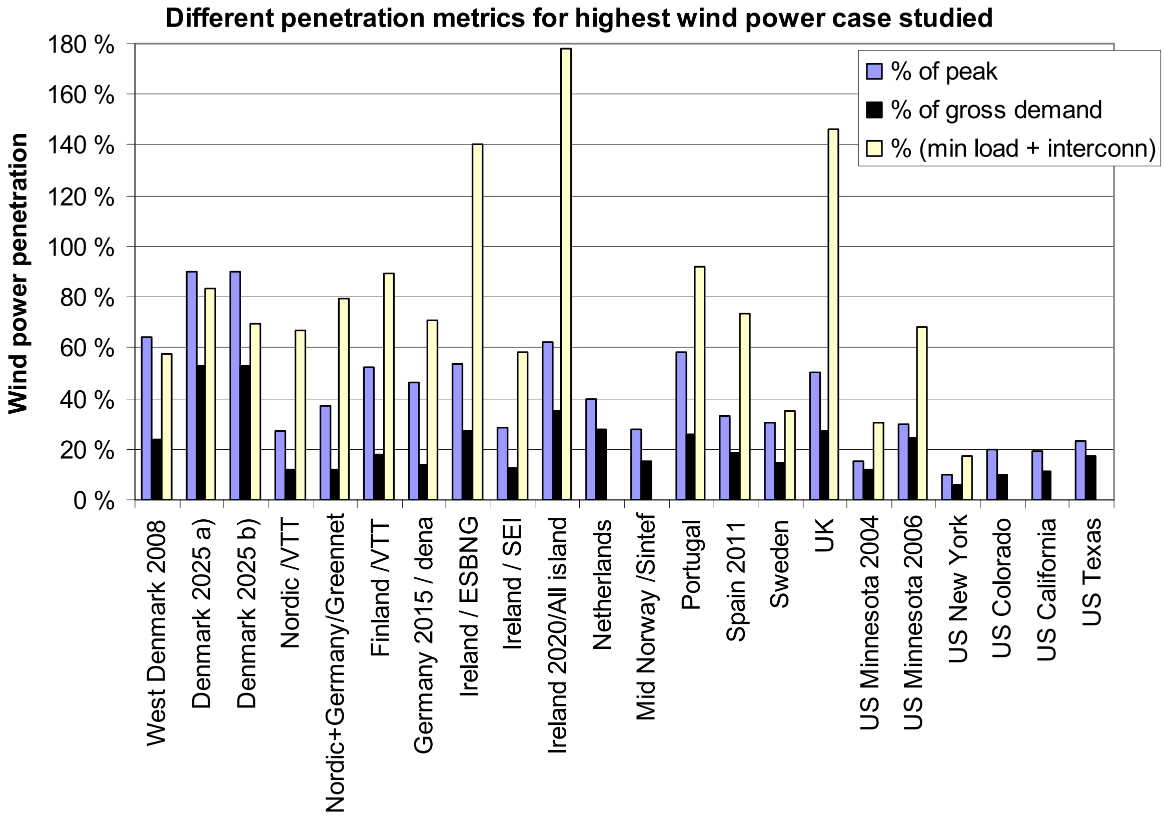


Fig 55. Comparison of the share of wind power in the power system (penetration levels) studied. For studies covering several countries, the aggregate penetration level has been calculated. Individual countries within the study cases can have significantly higher wind power penetration levels.

7.1 Summary of balancing requirement results

Summaries for the quantified results for balancing requirements presented in section 3 are presented in Fig 56 and Fig 57.

The increase in reserve requirement is most often estimated by statistical methods combining the variability of wind power with that of load. In some studies also the sudden outages of production are combined with reserve requirements (disturbance or contingency reserve). For the impact on operation of power systems, model runs are made and most results are based on comparing costs of system operation without wind and adding different amounts of wind. The costs of variability are also addressed by comparing simulations with flat wind energy to varying wind energy (for example in US Minnesota and Greennet Nordic + Germany). The results presented in Fig 56 for increase in reserve requirements due to wind power are from following studies:

- Finland and Nordic (Holttinen, 2004)
- Sweden (Axelsson et al., 2005)
- Ireland (Ilex et al., 2004)
- UK (Strbac et al., 2007)
- Germany (Dena, 2005)
- Minnesota 2006 (EnerNex/WindLogics, 2006)
- California (Porter et al., 2007).

If only hourly variability of wind is taken into account when estimating the increase in short term reserve requirement, the results are 4 % of installed wind capacity or less, with penetrations below 10 % of gross demand. When 4 hour forecast errors of wind power are taken into account, the increase in short term reserve requirement of 4–5 % of installed wind capacity has been reported, with penetration levels of 5–10 % of gross demand. The highest results in Fig 56 are from a study where four hour variability of wind (not forecast error), combined with load forecast error, results in 15 % reserve requirement at 10 % penetration and 18 % reserve requirement at 20 % penetration of gross demand (Strbac et al., 2007).

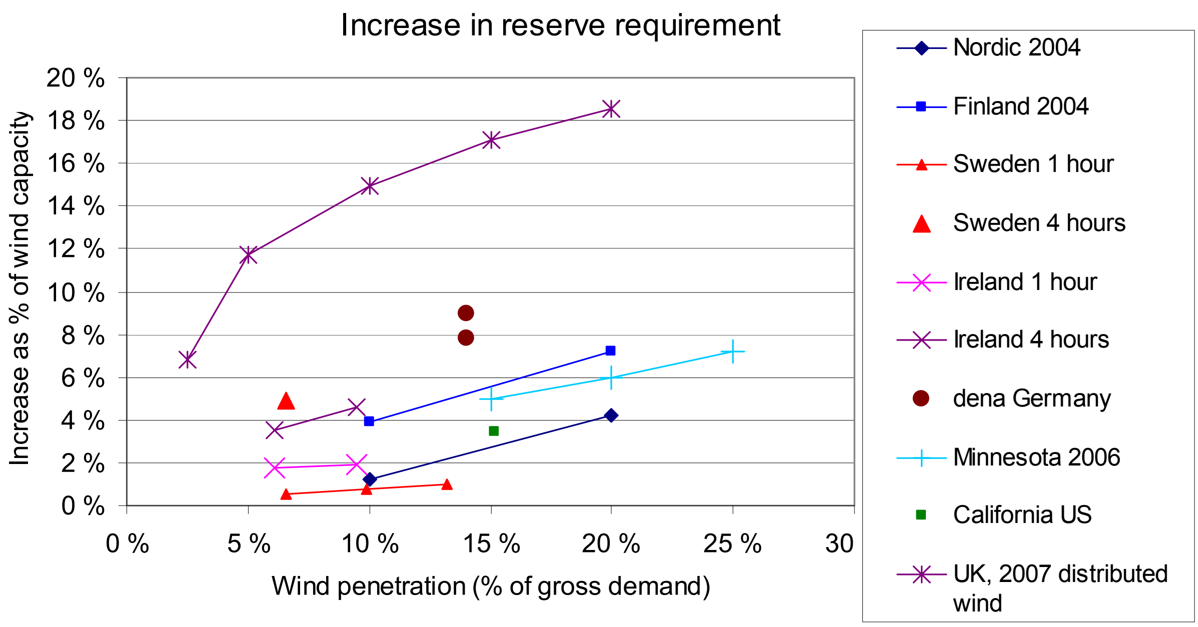


Fig 56. Results for the increase in reserve requirement due to wind power. German Dena estimates are taking into account the day-ahead uncertainty (for up and down reserves separately) and UK the variability of wind 4 hours ahead. In Minnesota and California, day ahead uncertainty has been included in the estimate. For the others the effect of variations during the operating hour is considered For Ireland and Sweden the 4 hour-ahead uncertainty has been evaluated separately.

The latest achievements in wind forecasting show a considerable improvement of predictions also in short time scales (see Section 2.1.2). If day-ahead forecast errors are left to be balanced with the short term reserves, the increase in short term reserve requirement is nearly 10 %. In this German study, the reserve requirement is taken as the average impact of day-ahead forecast errors of wind power, the maximum values would result in and increase that is 15–20 % of installed wind capacity (Dena, 2005). There are some studies showing larger increase in reserve requirement than shown here. Swedish TSO published estimates that are 35–48 % of installed wind capacity. As discussed in more detail in Section 3.6.2, this total comes from adding up several causes for reserves, part of which are more about flexibility in larger time scales of several hours in the power system. Californian ISO produced estimates for regulation (primary reserve) that are about 100–500 MW or 1–5 % of installed wind capacity. This regulation requirement is 10 times larger than that found in the CEC study performed by GE. No further analysis of this claim has been made.

The results presented in Fig 57 for increase in balancing costs due to wind power are from following studies:

- Finland and Nordic countries (Holttinen, 2004)
- UK (Ilex/Strbac, 2002; Strbac et al., 2007)
- Ireland (Ilex, 2004)
- Colorado (Zavadil et al., 2006)
- Minnesota (EnerNex/WindLogics, 2004 and 2006)
- California (Shiu et al., 2006)
- PacifiCorp (PacifiCorp, 2005)
- Nordic countries and Germany, Greennet (Meibom et al., 2009).

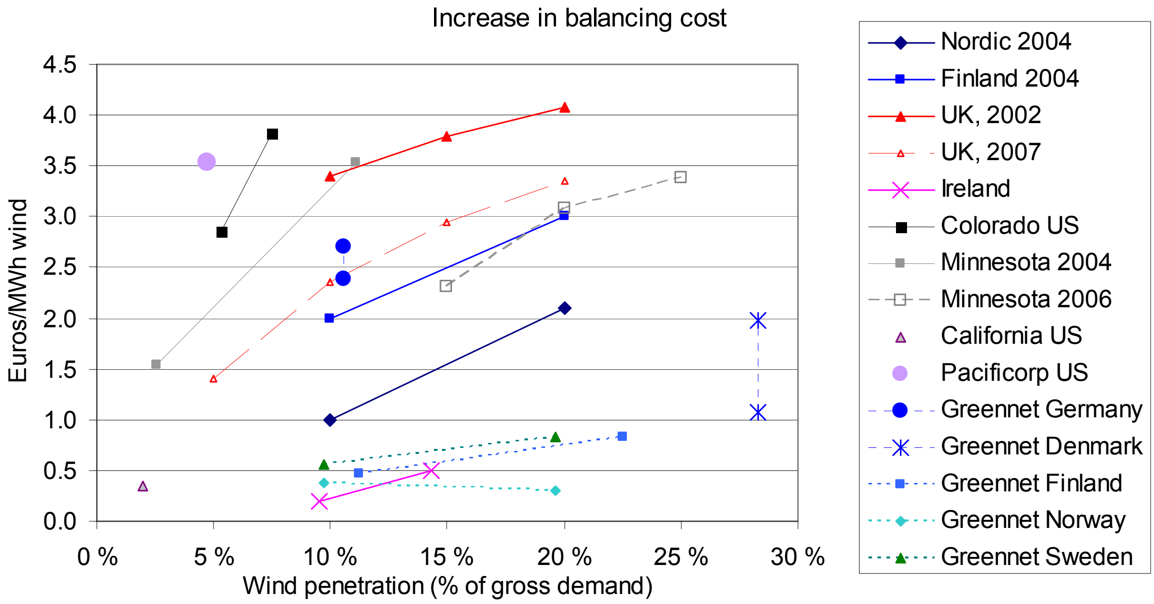


Fig 57. Results from estimates for the increase in balancing and operating costs due to wind power. The currency conversion used here is 1 € = 0.7 £ and 1 € = 1.3 US$. For UK, 2007 study the average cost is presented here, the range in the last point for 20 % penetration level is from 2.6 to 4.7 €/MWh.

In addition to estimates, there is some experience from Denmark for the actual balancing costs for the existing wind power. For West Denmark, the balancing cost from the Nordic day-ahead market has been 1.4–2.6 €/MWh for a 24 %

wind penetration (of gross demand) (Section 0). These numbers are quite in the middle of Fig 57.

The highest estimates of reserve requirements from Germany and UK are not reflected in balancing costs, as from both studies it was concluded that this amount of reserve can be handled with the current conventional power plants. From UK, only the increased cost of operating existing reserves has been estimated. At wind penetrations of up to 20 % of gross demand (energy), system operating cost increases arising from wind variability and uncertainty amounted to about 1–4 €/MWh. This is 10 % or less of the wholesale value of the wind energy. It can be seen that there is considerable scatter in results for different countries and regions. The following differences have been remarked:

- Different time scales used for estimating – For UK 2002 study, the increased variability to 4 hours ahead has been taken into account. For US studies also the unit commitment impact for day-ahead scheduling is incorporated. For the Nordic countries and Ireland only the increased variability during the operating hour has been estimated. For the Greennet study, the unit commitment and reserve allocation are made according to wind forecasts but the system makes use of updated forecasts 3 hours before delivery for adjusting the production levels.
- Costs for new reserve capacity investment – For the Greennet, UK and SEI Ireland studies only incremental increase in operating costs has been estimated whereas also investments for new reserves are included in some results (Nordic 2004 and Finland 2004).
- Larger balancing areas – The Greennet, Minnesota 2006 and Nordic 2004 studies incorporate the possibilities for reducing operation costs through power exchange to neighbouring countries/markets, whereas Colorado, California, PacifiCorp, German Dena study, Sweden, UK, Ireland and Finland studies analyse the country/market in question without taking transmission possibilities (giving balancing potential from neighbouring regions) into account. The two studies for Minnesota show the benefit of larger markets in providing balancing. The same can be seen from the Greennet study results and the Nordic 2004 results compared with results calculated for Finland alone. Larger power systems make it possible for smoothing of the wind variability.

- Greennet results for Denmark and Germany show that you get different costs depending on how much your neighbours have wind power. The higher costs refer to situation when FIN, SWE, NOR have 20 % penetration. The Norway results show that their flexibility is so high that there is no increase in operating costs when increasing wind penetration, the line is flat.

As shown in Table 4 the interconnection capacity to neighbouring systems is often significant. For the balancing costs, it is then essential to note in the study setup whether the interconnection capacity can be used for balancing purposes or not. A general conclusion is that if interconnection capacity is allowed to be used also for balancing purposes, then the balancing costs are lower compared to the case where they are not allowed to be used. Other important factors identified as reducing integration costs were aggregating wind plant output over large geographical regions, and operating the power system closer to the delivery hour.

Not all case studies presented results quantified as MW of increase in reserve requirements or monetary values for increase in balancing costs.

- In Sweden and Finland, the balancing costs as payments for wind power producers have been estimated from the balanging market (Nordic Regulating market) prices to be 0.3–1.4 €/MWh depending on how distributed the wind power is and on the market price level for balancing (Holttinen et al., 2006; Neimane & Carlsson, 2008). These balancing costs only include the costs related to unpredictability, i.e. wind power variability is handled in the Nordic day-ahead market. In Sweden, the use of 15 min operating reserves has been estimated to increase by 18–56 % of current amounts due to wind power forecast errors 1 or 4 hours ahead for 4000 MW wind power (8 % of gross demand) (Brandberg & Broman, 2007). The increased cost of system imbalances of Finland due to future wind power prediction errors was estimated to be 0.2–1 €/MWh for penetration levels of 1–10 % of gross demand, assuming the Nordic balancing market was available (no bottlenecks) (Helander et al., 2009).
- The use of an intra-day market to help reduce the imbalance costs of wind power has been examined in Germany (FGE/FGH/ISET, 2007), and for the Nordic market in Finland (Holttinen & Koreneff, 2007) and Sweden (Neimane & Carlsson, 2008). The conclusion is that at least for the current price assumptions, there is not a straightforward benefit to

use an intra-day market. This is because trading at an intra-day market would mean correcting all imbalances, whereas the imbalance payments only apply to the imbalances that affect the power system net imbalances, thus not 100 % of time (at low penetrations only 50 % of time).

- In Sweden the impacts of wind power forecast errors on hydro power efficiency were estimated for lower penetrations (<3 % of gross demand). At wind power levels of about 4–5 TWh/year the installed amount of wind power has to be increased by about 1 % to compensate for the decreased efficiency in the hydro system (Söder, 1994).
- For Nordic countries, the increase of losses due to bypass of water due to 12 % penetration of wind power was estimated to be equivalent of 1 % of wind power production (Holttinen, 2004).
- In Denmark the TSO has estimated the impacts of increasing the wind penetration level from 20 % to 50 % (of gross demand) and concluded that further large scale integration of wind power calls for exploiting both, domestic flexibility and international power markets with measures on the market side, production side, transmission side and demand side (Energinet.dk, 2007).
- In simulated cases in the Netherlands it is shown that the international trade of electricity, in particular postponing market gate closure, is an important solution for integrating more wind power in an efficient way. Importantly, wind power worsens the business case for thermal generation, in particular for CCGT during peak demand and for base-load coal during low demand (Ummels, 2009).
- The Irish All Island Grid Study shows that going from 2 to 6 GW wind, the operational costs of the electricity system fall by €13/MWh when compared to the base case – due to cost benefit approach in the study, the cost component was not published as such (All Island Grid Study, 2008).
- New York, 10 % penetration of capacity, incremental regulation due to wind was found to be 36 MW. No additional spinning reserve was needed. Incremental intra-hour load following burden increased 1–2 MW / 5 min. Hourly ramp increased from 858 MW to 910 MW. All increased needs can be met by existing NY resources and market processes. System cost

savings of \$335–\$455 million for assumed 2008 natural gas prices of \$6.50–\$6.80/MMBTU were found. Day-ahead unit-commitment forecast error σ increased from 700–800 MW to 859–950 MW. Total system variable cost savings increases from \$335 million to \$430 million when state of the art forecasting is considered in unit commitment (\$10.70/MWh of wind). Perfect forecasting increases savings an additional \$25 million (GE Energy, 2005).

- In Texas, the regulation time scale impacts (second-to-second variability) were studied and a 54 MW and 48 MW increase in up-regulation and down-regulation, respectively was found. The cost of regulation per MWh of wind using a state-of-the-art wind forecast increases as wind capacity reaches 10,000 MW up to \$.27/MWh, but then decreases to an actual savings of regulation costs at the 15,000 MW penetration level of \$.18/MWh. The reason for this is that even with the higher regulation requirements, the regulation clearing prices for the ancillary service market decrease as the unit commitment problem is solving to commit cheaper units because of the added wind capacity. The avoided cost of wind power was estimated to about \$55/MWh of wind energy (GE Energy, 2007).
- Regarding storage, the value of storage in the power system operation in UK was estimated to be 252–970 £/kW (Strbac et al., 2007). For Germany a 27 M€/year revenue could be foreseen for 400 MW CAES (250 M€ investment) (FGE/FGH/ISET, 2007). In the NL international exchange was seen as a more promising alternative to storage in the system (Ummels, 2009). In Ireland adding storage did not bring additional value in the All Island Grid Study results (All Island Grid Study, 2008).

For wind penetration levels of 10–20 % of gross demand, the cost effectiveness of electricity storage in power systems is still low (excluding hydro power with large reservoirs or pumped hydro). With higher wind penetration levels the extra flexibility that also storages can provide will be beneficial for the power system operation. It is important to notice, however, that any storage should be operated according to the needs of aggregated system balancing. It is not cost effective to provide dedicated back-up for wind power in large power systems where the variability of all loads and generators are effectively reduced by aggregating, in the same way as it is not effective to have dedicated storage for outages in a certain thermal power plant, or having specific plants following the variation of a certain load.

7.2 Summary of simulation model review tables

A summary of tables in Appendix 2 is presented in Table 22. The main idea has been to present tables from simulations regarding balancing requirements. Most studies are based on comparing results and costs of system operation without wind and adding different amounts of wind. The costs of variability are also addressed by comparing simulations with flat wind energy to varying wind energy (US Minnesota and Nordic + Germany).

The table can be used to look for explanations for different results: what has been taken into account in the estimates. In (Söder & Holttinen, 2007) the best possible methodology for simulations means taking all possible market and grid dynamic aspects into account, which is impossible in practice due to the small time step (less than second) and long simulation time (years). Assumptions need to be made when simulating the system operation.

The most general finding comparing the study set-ups is the use of interconnection capacity – this is crucial when estimating the impacts of wind power.

Table 22. Summary of review tables in Appendix 2 that are describing energy system modelling with and without wind to assess wind integration impacts on balancing.

Set up		**SE Söder 1994**	**Nordic Holttinen 2001**	**Nordic + GER Meibom 2009**	**US Minnesota Enernex 2004**	**US Minnesota Enernex 2006**	**IR ESBNG 2004**	**IR SEI 2004**	**NL 2009**
A	**Aim of study**	1 what happens with x GWh wind (1)	1 what happens with x GWh wind	1 what happens with x GWh wind	1 what happens with x GWh wind	1 what happens with x GWh wind	1 what happens with x GWh wind (2)	1 what happens with x GW wind (3)	1 what happens with x GWh wind
M	**Method**	1 add wind energy (4a)	1 add wind energy	1 add wind energy (4b)	1 add wind energy (6)	1 add wind energy (6)	2 wind repl. capacity (5, 6)	1 add wind energy	1 add wind energy
S	**Simulation model of operation**	3 determ. planning with stoch. wind forecast err. (8)	2 determ. simulation, 30 hydro inflow cases	4 Stochastic simulation several cases	2 determ. simulation several cases	2 determ. simulation several cases	2 determ. simulation, unit commitm and dispatch	2 determ. simulation	5 probablilist. chronolog. (14)
Simulation detail									
R	**Resolution of time**	hour;	week (9); for 30 years	hour, for one year	hour; for 3 x year	hour; for 3 x year	hour; for1 year	half hourly	15 min, one year (15)
P	**Pricing method**	5 other: (10a)	1 costs of fuels 3 perfect market	1 costs of fuels/start-up 3 perfect market	1 costs of fuels	1 costs of fuels	1 costs of fuels 5 other: (10b)	1 costs of fuels	1 cost of fuels 3 perfect market
D	**Design of remaining system**	1 constant 6 load increased correspond. to wind increase	1 constant 4 changed operation due to wind power	1 constant 4 changed operation due to wind power 5 perfect trading rules	1 constant	4 changed operation due to wind power 5 perfect trading rules 6 plant and transm added	1 existing plant reduced when wind added (11a).	1 constant, (11b) with new CCGTs and OCGTs added to replace retired plant	1 constant 4 changed operation due to wind power

Uncertainty and balancing									
I	**Imbalance calculation**	2 wind + load	no imbalance calculation	1 only wind 4 wind + production for reserve alloc	3 wind + load +production	3 wind + load + production	4 other: wind + production.	3 wind + load + production	3 wind + load + production
B	**Balancing location**	1 dedicated source 4 other (12)	no imbalance calculation	3 also outside region	2 from the same region	3 also outside region	2 from the same region	2 from the same region	3 also outside region
U	**Un-certainty treatment**	3d: wind forecasts (1–2 hours…day ahead) 5 load forecasts	2 hydro inflow uncertainty: 3 no wind forecasts (13a) 6 thermal outages	2 hydro inflow uncertainty: 3d wind forecasts 3–36 h ahead (13b)	3d wind forecasts day-ahead (13d) 5 load forecasts 6 thermal outages	3d wind forecasts 1h & day ahead (13d) 5 load forecasts 6 thermal outages	3 wind forecasts: average wind (13e) 6 thermal outages	3d wind forecasts 1 and 4 h (13f) 5 load forecasts (13g) 6 thermal outages	1 transm. margins 3d wind forecasts
Power system details									
G	**Grid limit on transm.**	1 no limits	2 constant MW limits	2 constant MW limits	1 no limits	2 constant MW limits	1 no limits	1 no limits	2 constant MW limits
H	**Hydro power modeling**	1 head height 2 hydrological coupling 3 hydrological restrictions 4 availability of water 5 optimization	1 head height 2 hydrological coupling 3 hydrological restrictions 4 availability of water 5 optimization	3 hydrological restrictions 4 availability of water 5 optimization	6 limited, deterministic run-of-river 7 interaction with hydro not significant	6 limited, deterministic run-of-river 7 interaction with hydro not significant	8 other: hydro plant operating in accordance with historical production profiles	8 other: hydro plant operating in accordance with historic profiles	7 interaction with hydro not significant

T	**Thermal power modeling**	no thermal power in the system	only availability	2 start/stop 3 efficiency 4 heat prod.	1 ramp rates 2 start/stop 3 efficiency	1 ramp rates 2 start/stop 3 efficiency	1 ramp rates 2 start/stop	1 ramp rate 2 start/stop 3 efficiency	1 ramp rates 2 start/stop 3 efficiency 4 heat prod
W	**Wind power modeling**	1a wind speed + power curve (8 sites) Stochastic forecast errors	1a few wind speed time series (weekly), 30 years of data	1a and b wind speed and power time series. 1d smoothing 3 synchr. wind data with load 4 future wind distribution	1c time series: re-analysis wind (50 sites) 2b wind profiles 3 synchr. wind / load 4 future wind distribution	1c time series: re-analysis wind 2b wind profiles 3 synchr. wind / load 4 future wind distribution	1b wind power time series 19 sites 2b wind profiles 4 future wind distribution	1 time series: 10 sites 2b wind profiles 4 scenarios for future wind power distribution	1a wind speed + power curve (38 sites) 1d smoothing 4 future wind distribution

(1) how much wind is possible (wind power increased until evaluation strategy did not work (2) impact of Wind Power on operation of conventional plant (3) impact of wind on operating reserve (4a) load is increased same amount of GWh as wind (4b) comparison between stochastic, variable wind production and equivalent predictable, constant wind production (5) while maintaining system adequacy (6) For capacity credit: a – chronological, using wind power and load profiles (7) capacity credit calculated using wind power and load profiles. (8) Deterministic planning but evaluation based on rescheduling every hour based on stochastic forecast errors (9) 4 load profiles, hydro inflow and wind assumed constant during the week (10a) "integration cost" was calculated as needed extra wind energy (MWh) to compensate for lost hydro (10b) additional reserve capital costs attributable to wind energy calculated (11a) 5000MW peak case: existing plant reduced when wind added. 6500MW peak case: mixture of (CC) and (CT) units (11b) constant, with new CCGTs and OCGTs added to replace retired plant (12) Wind power balancing was performed in one river and the result was upscaled to Sweden (13a) some wind uncertainty through weekly uncertainty in water value calculations (13b) std 15–18 % of installed capacity 8–36 h ahead (13c) load forecasts: 2.5 % mean forecast error (13d) 20 % MAE day-ahead (13e) average 24 h wind was used as the forecasted value for commitment algorithm, with variations above or below this used for dispatch algorithm (13f) MAE 14–18 % (13g) load forecast errors: 1 hour – 40 MW, 4 hours – 60 MW. (14) single wind forecast, hourly wind power updates (15) weekly optimisation

7.3 Summary of grid reinforcement and efficiency results

With current technology, wind power plants can be designed to meet industry expectations such as riding through voltage dips, supplying reactive power to the system, controlling terminal voltage, participating in system operation with output and ramp rate control, and providing SCADA information. In areas with limited penetration, system stability studies have shown that modern wind plants equipped with power electronic controls and dynamic voltage support capability can improve system performance by damping power swings and supporting post-fault voltage recovery. The results of studies performed in UK suggest that at higher penetration levels, requiring sufficient fault ride through capability for large wind power plants is economically efficient compared with modifying the power system operation for ensuring power system security in case wind farms are not having fault ride through capability. In stability studies of the Iberian peninsula it is shown that to reach penetration levels of more than 10 %, fault ride through capability is required in majority of wind power plants. Also the German studies conclude that a passive fault ride through capability will not be sufficient in the future. In addition, the turbines have to be able to provide reactive power to the grid. In a US study it was found that wind power plants with some dynamic reactive capability may reduce or eliminate the need for dynamic reactive devices on the transmission system (Loutan et al., 2007).

Dynamic line ratings, taking into account the cooling effect of wind together with temperature in determining the transmission constraints, can increase transmission capacity from the North to the middle of Germany by 40 to 90 % at times when the German wind power generation is above 75 % of the installed capacity. In 99 % of the time the increase is above 15 % for all lines, except some very unfavourable cases, where only an increase of 5 % is calculated (Lange and Focken, 2008).

Norwegian study shows that the power smoothing effect of geographically dispersed wind power plants gives a significant reduction of discarded wind energy in constrained networks, compared to a single up-scaled wind power plant site (Korpås et al., 2006). In both Norway and Sweden it has been shown that with comparatively high grid costs it can be economically preferable to spill wind power than to increase the transmission capability and that coordination of hydro power and wind power in a region with limited export capability can reduce the need for grid upgrade (Matevosyan, 2006; Tande & Uhlen, 2004).

Grid reinforcement may be needed for handling larger power flows and maintaining stable voltage, and is commonly needed if new generation is installed in weak grids far from load centers. The issue is generally the same be it modern wind power plants or any other power plants. The cost of grid reinforcement due to wind power is therefore very dependent on where the wind power plants are located relative to load and grid infrastructure, and one must expect numbers to vary from country to country.

Some innovative approaches to transmission expansion for remote wind projects have been undertaken recently in the US. The Electric Reliability Council of Texas (ERCOT) has designated specific remote areas with excellent wind resources as Competitive Renewable Energy Zones (CREZ), and undertaken a transmission expansion plan to link these regions with load centers. In ERCOT, once a transmission line has received the necessary approvals, its cost is rolled into the rate base and all customers pay a pro rata share of its cost. The plan which was approved consisted of an integrated 345 kV system expansion with 2 376 miles of new right-of-way to accommodate a total of 18456 MW of wind capacity at a cost of $4.93 billion. Production cost savings of 2.4 billion dollars per year were estimated for this scenario. California, Colorado, and Minnesota have similar processes underway.

The European wide wind integration studies Tradewind and EWIS show where increased bottlenecks can be expected in the meshed European transmission grid with wind power penetrations from 2015 onwards, and which network reinforcements can bring significant benefits to the system (van Hulle et al., 2009).

The reported results in the national case studies for grid reinforcements are:

- UK: £65–125 / kW (85–162 €/kW) for 26 GW wind (20 % energy penetration) and £35/kW–£77/kW for 8 GW of wind (Strbac et al., 2002).
- Netherlands: 60–110 €/kW for 6000 MW offshore wind (Jansen & deGroot, 2003).
- Portugal: from 53 €/kW (only summing the proportion related to the wind program of total cost of each grid development or reinforcement) to around 100 €/kW (adding total costs of all grid development items) for 5100 MW of wind (ref).

- German Dena study results are about 100 €/kW for 36 000 MW wind (Dena, 2005).
- Ireland: The All Island Grid Study indicates that for 2.25 GW of renewables, of which 2 GW is wind, modest amounts of additional high voltage transmission are required. For 6.6 GW of renewables including 6 GW wind, total capital investment in transmission of in excess of €1000 million will be required. This represents a total investment of €154 per kW of renewable generation installed. The incremental transmission investment required to integrate the 4.3 GW beyond 2.25 GW amounts to €212 per kW of renewables. When annualised these costs were modest adding of the order of 1 or 2 % to the cost of electricity even in the highest wind portfolios. The single biggest issue will be getting public acceptance of the transmission. Significant reactive power issues were identified that will need to be addressed more fully.
- In Denmark investments for 270 €/kW for additional 3 GW of wind power were estimated, assuming that about 40 % of total grid reinforcement cost is attributable to wind power (Electricity Infrastructure Committee, 2008). A previous Denmark study shows grid reinforcement cost of 63–117 €/kW for 2250 MW of additional off-shore wind power in 2025, excluding the costs of getting the offshore production on shore. No additional network reinforcement costs for increasing onshore wind power with 700 MW from 2007 to 2025 was foreseen (EA Energianalyse, 2007).
- In the US, a recent study reviewed a sample of 40 detailed transmission studies from 2001–2008 that have included wind power. The range of transmission costs for wind investigated in these studies ranged from $0/kW to over $1500/kW. The majority of studies, however, have a unit cost of transmission that is below $500/kW, and a median cost of $300/kW. One of the most interesting findings from the study is that unit transmission costs of wind do not appear to increase significantly with higher levels of wind penetration. Rather, studies with the highest additions of wind energy tend to have lower unit costs of transmission, indicating that economies of scale appear to come into play when accessing large resource areas.

The costs of grid reinforcement needs due to wind power cannot be directly compared, as they will vary from country to country depending greatly on location of the wind power plants relative to load centers. The grid reinforcement costs are not continuous; there can be single very high cost reinforcements. Grid reinforcement costs are by nature dependent of the existing grid. The costs vary with time and are dependent on the time instant the generator is connected. After building some lines, often several generators can be connected before new reinforcement needs occur. After a certain time instant, new lines, substations or something else is needed. The same wind power plant, connected at different time instant, therefore may lead to different grid reinforcement costs. For transmission planning, the most cost effective solution in cases that demand considerable grid reinforcements would be to build transmission network for the final amount of wind power in the network – instead of having to upgrade transmission lines in several phases.

There can also be differences in how the costs are allocated to wind power. It is also important to note that grid reinforcements should be held up against the option of curtailing wind or altering operation of other generation in cases where grid adequacy is insufficient during only part of the time or for only some production and load situations.

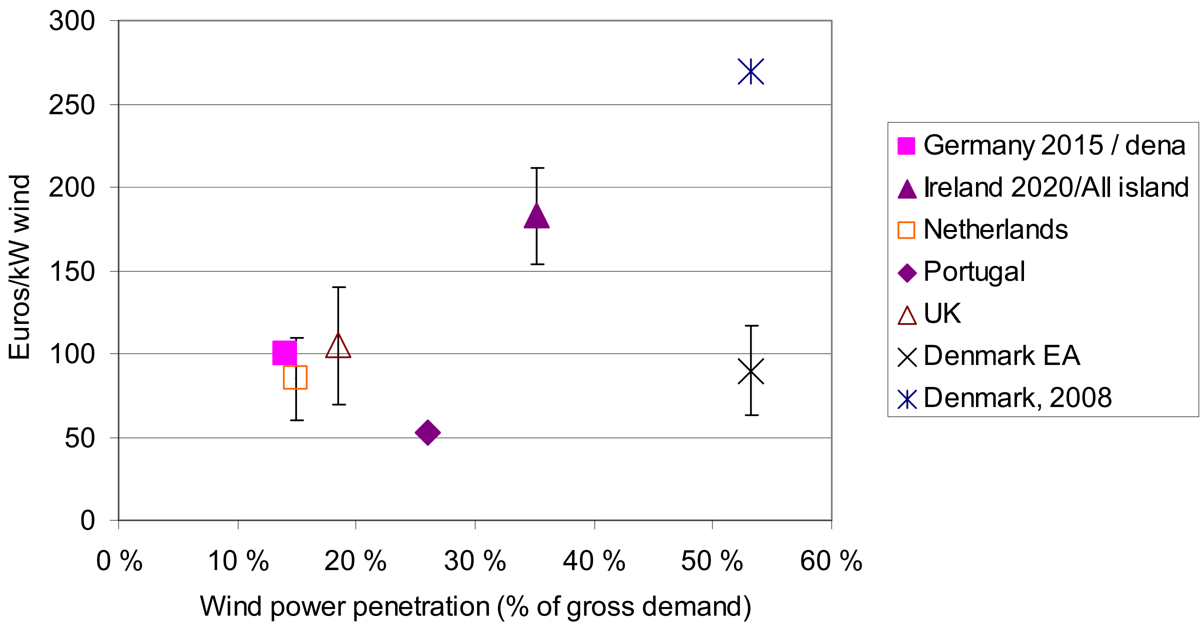


Fig 58. Comparison of the estimated costs for grid reinforcement costs due to wind power. For Denmark, the cost of increasing wind penetration from 20 % to 50 % is allocated to added wind power. For Ireland the range comes from allocating the cost for all renewables from 0 % penetration and for allocating the cost for added renewables (from 2.25 GW to 6.6 GW).

7.4 Summary of power adequacy/capacity credit results

The capacity credit of wind power answers questions like: Can wind substitute for other generation in the system and to what extent? Is the system capable of meeting a higher (peak) demand if wind power is added to the system? This is related to the long-term reserve or planning reserve that power systems carry.

Wind generation will provide some additional load carrying capability to meet projected increases in system demand. This contribution can be up to 40 % of installed wind power capacity (in situations with low wind penetration and high capacity factor at times of peak load), and down to 5 % in higher wind penetrations, low capacity factor at times of peak load or if regional wind power output profiles correlate negatively with the system load profile (Fig 59). The aggregation benefits apply to capacity credit calculations – for larger geographical areas the capacity credit will be higher.

The wind capacity credit in percent of installed wind capacity is reduced at higher wind penetration, but depends also much on the geographical smoothing. This is demonstrated comparing the cases of Mid Norway with 1 and 3 wind power plants. In essence, it means that the wind capacity credit of all installed wind in Europe or the US is likely to be higher than those of the individual countries or regions, even if the total penetration level is as in the individual countries or regions. Indeed, this is true only when assuming that the grid is not limiting the use of the wind capacity, i.e. just as available grid capacity is a precondition for allocating capacity credit to other generation.

The results presented in Fig 59 for capacity value of wind power are from following studies:

- Germany (Dena, 2005)
- Ireland (ESBNG, 2004)
- Norway (Tande & Korpås, 2006)
- UK (Ilex & Strbac, 2002)
- US Minnesota (EnerNex/WindLogics, 2004; EnerNex/WindLogics, 2006)
- US New York (GE Energy, 2005)
- US California (Shiu et al., 2006).

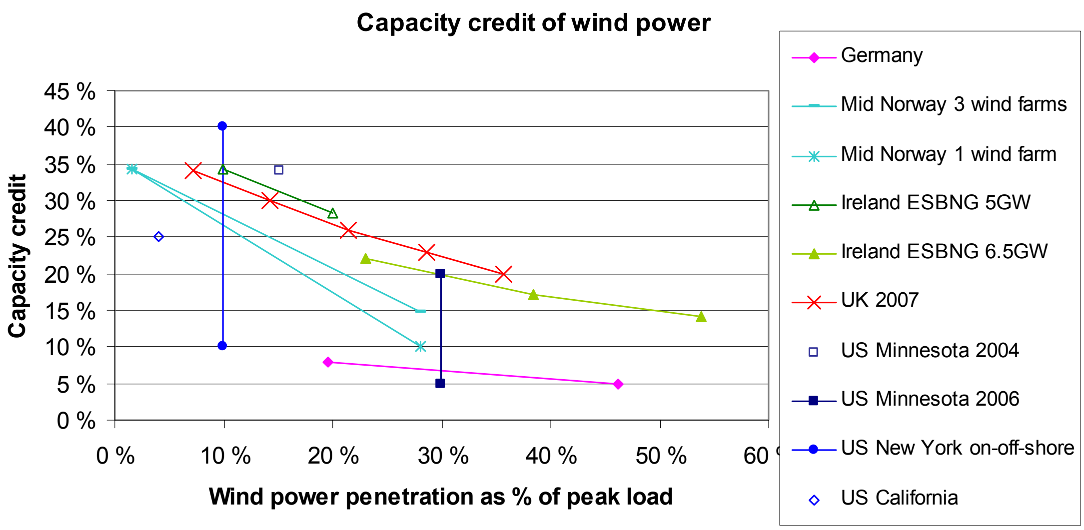


Fig 59. Capacity credit of wind power, results from eight studies. The Ireland estimates were made for two power system configurations, with 5 GW and 6.5 GW peak load.

Results for the capacity credit of wind power in Fig 59 show a considerable spread. One reason for different resulting levels arises from the wind regime at the wind power plant sites and the dimensioning of wind turbines. This is one explanation for low German capacity credit results shown in Fig 59. For near zero penetration level, all capacity credit values are in the range of the capacity factor of the evaluated wind power plant installations. The correlation of wind and load is very beneficial, as can be seen in the case of US New York offshore capacity credit being 40 %.

Although the use of alternative, simplified methods appears to be somewhat popular, many of these have not been compared to the more robust approaches based on reliability analysis. We strongly encourage this comparison so that the trade-offs of using simplified approaches is transparent. There are also new more elaborate methodologies emerging to study capacity credit. For example, the risk assessment methodology in section 5.6 (Portugal and Spain) calculates not only the general adequacy of the generating system but also the risk associated to the operating reserve.

In some reports the term “capacity cost” is used. The meaning of this is the cost for the difference between capacity credit for wind power and capacity credit for a conventional power plant. It is then important to consider the cheapest possible compensation in order not to overestimate this cost. Firstly it is important to remember that the capacity credit is normally calculated for a system where there is danger for capacity deficit only during a time period in the range of hours per year or less. If the capacity credit is not high enough then it is necessary to install extra capacity, but then this extra capacity is only used, perhaps, some hours per year. With this level of utilization, open cycle gas turbines (OCGTs) are to prefer. These units have comparatively low investment costs. An even cheaper solution in many cases is demand side management, DSM. In order to obtain a realistic “capacity cost” it is essential to not overestimate the cost of the compensation (Söder & Amelin, 2008).

8. Current practice and recommendations

Challenges for estimating the impacts of wind power include developing representative wind power production time series across the area of study, taking into account the (smoothed out) variability and uncertainty (prediction errors) and then modelling the resultant power system operation. The state-of-the-art best practice so far includes:

- Capturing the smoothed out variability of wind power production time series for the geographic diversity assumed. Use actual data from several wind power plants and met towers, or synchronized weather simulation. Utilize wind forecasting best practice for estimating the uncertainty of wind power production.
- Examine wind variation in combination with load variations, couple with actual historic utility load and load forecasts.
- Capture system characteristics and response through simulations and modelling of system operation.
- Examine actual technical costs independent of tariff design structure.
- Compare the costs and benefits of wind power.

In general the question is in most cases whether extra investments to power system are economically profitable or not in the new system with larger amount of wind power – not only that a certain amount of extra reserve capacity and/or new transmission lines are a prerequisite in order to build any wind power.

For high penetration levels of wind power, the optimisation of the integrated system should be explored. Modifications to system configuration and operation practices to accommodate high wind penetration may be required. Not all current system operation techniques are designed to correctly incorporate the characteristics of wind generation and surely were not developed with that objective in mind. For high penetrations also the surplus wind power needs to be dealt with, e.g. by transmission to neighbouring areas, storage (e.g. pumping hydro or thermal) or even demand side management (avoiding wind power curtailment). There is a need to assess wind power integration at the international level, for example to identify the needs and benefits of interconnection of national power systems.

Power systems are different in how much flexibility exists and how flexibility can be increased in a cost effective manner when high amounts of wind power are integrated. A number of insights related to the integration of increasing amounts of wind power in power systems gained from the work to date include:

- ***Larger balancing area size and wind aggregation***: both load and generation benefit from the statistics of large numbers as they are aggregated over larger geographical areas. Larger balancing areas make wind plant aggregation possible. The forecasting accuracy improves as the geographic scope of the forecast increases; due to the decrease in correlation of wind plant output with distance, the variability of the output decreases as more plants are aggregated. On a shorter time scale, this translates into a reduction in reserve requirements; on a longer time scale, it produces some smoothing effect on the capacity value. Larger balancing areas also give access to more balancing units.

- ***Available transmission capacity***: Transmission helps to achieve benefits of aggregating large scale wind power development and provides improved system balancing services. This is achieved by making better use of physically available transmission capacity and upgrading and expanding transmission systems. High wind penetrations may also require improvements in grid internal transmission capacity.

- ***System operation***: Integrating wind generation information in system operation both real-time and with updated forecasts up to day-ahead will help manage the variability and forecast errors of wind power. Shortening the gate closure time in market operation practices will help integration but may require improvements in the operating tools. Well-functioning hour-ahead and day-ahead markets can help in providing the balancing energy required by the variable-output wind plants more cost-effectively.

- ***Enhancing wind power plant capabilities***: Improvements in wind-plant operating characteristics will enhance reliable operation of the system through the ability to provide voltage control at a weak point in the system, the ability to provide an inertial response in a stability constrained system, the ability to participate in providing ancillary services, and the ability to ride through faults (voltage and frequency deviations) without disconnection.
- ***System expansion***: Sufficient flexibility in new generation additions as well as increased demand-side-management will help to accommodate increased variability expected due to the increased wind plant production.

Regarding estimating the capacity value of wind power, there are several approaches used. Determining the Loss-of-Load-Probability (LOLP) of the power system for different load levels is the most rigorous methodology available. It is not widely accepted to allocate costs for wind power due to its lower capacity value than conventional generation. If this approach is taken, then comparisons should be made with a conventional power plant providing the same annual energy than wind power and the most cost-effective options for providing power during peak load times should be used in cost calculations.

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Appendix 1: National activities

A wide range of case studies from different power systems have already been made and case studies will also be made during the next 3 years. Here a short overview of the on-going work in 2009–2011 is given.

Denmark

Risø DTU has several ongoing projects within wind integration in power systems. The experiences and results from these projects will used as input to the next phase of Task 25. Examples are:

- Risø DTU is working with estimation of the demand for minute reserves in the power systems as a function of installed wind power capacity in the EU funded SUPWIND project.
- Demonstration of decision support tools building on the existing Wilmar Planning tool for managing power systems with high wind power penetration with Ireland as case study will take place in the EU funded Anemos Plus project and with Denmark as case study in the SUPWIND project.
- The influence of plug-in electric and hybrid electric vehicles for wind power integration is investigated in a Phd project and in a Danish EFP 2007 research project (title: Power for road transport, flexible power systems and wind power). The influences on both day-to-day operation and on investments are analysed.
- The long-term development of power systems with high wind power penetration are analysed with optimisation models generating investments.

- Simulation of wind power time series, particularly relevant for large scale offshore locations with geographical concentration of the wind power.
- Frequency control of synchronous power systems with large scale wind power integration.

Finland

On-going national studies at VTT include a PhD work on large share of wind and renewable energy in the Finnish energy system. The planned work for 2009–11 includes work of VTT and Helsinki Technical University in:

- different options of grid connection of large offshore wind farms in Finland
- the variability of wind power in less than an hour time scale and impacts on reserve requirements
- capacity credit of wind power in Finland
- impact of prediction errors of wind to Finnish power system
- impact of wind power on the Nordic energy balance and mitigation impacts of increasing flexibility options like heat storages and plug-in vehicles
- wind power impacts on stability.

Germany

To investigate the optimal integration of wind energy into the German electricity supply system of the future, a follow up on the Dena Grid Study is currently on the way. The so called Dena Grid Study II will extend the period under review to 2020/25, when renewables are expected to reach a 30 % contribution to the German electricity production. The aim of the study is to develop a long-term plan for the integration of wind energy (and other renewable energies) into the grid. The research is structured in three main parts:

- generation of time series for the future input of wind energy and its forecast
- research into the further development of the transmission grid
- optimization of the integration of wind energy by increased flexibility of the electricity system.

The new Renewable energy act (EEG), which came into force in January 2009, provides the possibility to give economic incentives to wind farm owners for improved integration of wind power.

- Wind farm operators can opt to sell the power on the market (i.e. EEX) instead of selling for the fixed feed-in tariff (§ 17).
- A bonus for system services can be paid for turbines complying with a new grid code (§§ 29, 66).
- Financial incentives may be given to improve system integration (§ 64).

The government commissioned studies to give recommendations for the detailed support schemes and the economic incentives needed.

In the framework of the RAVE (research at alpha ventus) research initiative the environment ministry is funding the research and demonstration project RAVE Grid integration, to investigate methods to forecast and control offshore wind power in Germany in the future system.

Ireland

Ireland's existing work revolves around adapting the All Island Grid Study methodology to investigate the impact of additional storage, interconnection and/or demand side management. The All Island Grid Study employs a cost benefit analysis approach. This methodology will be further adapted to investigate the impacts (cost and benefits) that large scale electrification of our transport system would have on the ability to integrate wind power in Ireland. This work will be done in collaboration with colleagues from RISO Denmark. Planning and upgrading the transmission system to accommodate very high penetrations of wind power is now proving to be a major obstacle. In Ireland and elsewhere it is proving difficult to build new transmission mainly due to public opposition. Therefore it is important that optimal use (i.e. maximise the amount of wind energy) is made of existing transmission infrastructure and that any expansions are also optimised. This will almost certainly require new planning methods and criteria (e.g. probabilistic as opposed to deterministic) and this will be the main focus of Ireland's participation in the extended Task 25. This work will be done in collaboration with other participants but in particular with NREL in the USA and will build on existing collaboration in this area.

Netherlands

TUD is starting up research on transmission planning with high penetration of renewables. Currently, TUD concentrates on two themes: improving local wind farm-grid and distributed generation-grid interaction and balancing production and demand with a large amount of offshore wind.

ECN has proposed a large project North Sea SupraGrid that can act as the national project of Task 25 if approved. ECN, TUD Electrical Power Systems and TUD Electrical Power Processing will collaborate in the project. The objective of the project is to determine the best solution (modular, flexible, most cost effective) for a high capacity supranational offshore grid, connecting all future wind farms at the northern part of the North Sea. Different solutions will be investigated. For the most promising solution a multi-terminal converter controller will be developed and tested and the SupraGrid will be optimized. A second objective is to determine the effects of the SupraGrid on the national grids: an operating strategy of the SupraGrid will be developed to regulate power exchange correctly and avoid congestion and the effect of the SupraGrid on national grid stability will be investigated. Finally, the costs, benefits, policies and regulations related to realisation of the North Sea SupraGrid will be investigated and first steps towards a roadmap will be taken.

Norway

Planned studies will focus on offshore wind power in the Northern Europe.
Studies include:

- impact of offshore wind on power flows and market prices
- assessment of market solutions
- investigations of an offshore super-grid for connecting offshore wind farms, oil-rigs and transmission to shore.

Portugal

The Portuguese national projects in 2009–2011 are centered on the following topics:

- Optimizing The Power System Operation and the Grid Infrastructure for the Integration of Large Scale Variable Generation. This task will contribute to move this area towards the 2020 European Power System: that requires the development of new Wind Power Plant dynamic models for power system stability studies, the implementation of tools to enable a time-dependent transmission capacity (by on-line condition monitoring) and the use of DGS as grid active voltage controllers. Within this task, the ancillary services will be coordinated by the integration of balancing markets and the coordination of reserves within other EU grids/control areas. The operation and optimization of the power systems needs to be based on solid strategic aspects, especially when deciding where to install new production facilities or power lines. A significant research effort will be dedicated to offshore networks, as well as to grid connection from off-shore generation to the mainland system, given their critical contribution for the collection of wind and ocean generated electric power.

- Active Distribution Networks, Demand Side Management, New Market Places. Flexible scheduling tools are developed, which contemplate the trade-off between direct and reserved power, and react adequately to the variable and uncertain conditions of wind power, while ensuring the double-objective of minimizing costs, together with (whenever applicable) environmental impacts. The development of active distribution networks requires the adoption of a communication infrastructure between the control center/data management system and the different network devices as well as dispersed generation and storage units, including micro-generation, plug-in vehicles and consumers. A holistic application of demand side management (DSM) and the flexibility of load scheduling it involves, will contribute decisively to achieve the goals of the future power system, by reducing the overall system costs and enable the optimization of the power reserves. Also the development of market and pool models for high penetration of wind power and other time-depend and low forecastable renewable resources are addressed.
- Virtual Renewable Power Plants. This task addresses the correlation of renewable distributed resources, the assessment of the excess of renewable energy generation and the consequent need for added energy storage capacity both on large/national and small/local bases (e.g. pumped hydro, VRB batteries and plug-in vehicles). The Virtual Renewable Power Plant (VRPP) concept enables the plant's power and

condition monitoring and the control of DGS (distributed generation systems) by emulating their performance as a whole single power plant. That enables to combine regional/local production of different sources (e.g. biomass for electricity generation integrated with wind and PV applications) with the objective to achieve a more smooth and regulate generation, offering the possibility to reduce the capacity of the transmission line and integration panel or substation. Moreover it enables the clustering of wind generation (onshore and offshore) for power output smoothing, control and curtailment.

Spain

On-going national studies at UCLM-IER (Universidad de Castilla-La Mancha / Instituto de Investigación de Energías Renovables) include the PhD work on wind and renewable energy in the Spanish power system:

- modeled and hybrid system integration based on renewable energy using hydrogen as energy vector
- development and validation of wind farm models: aggregated behavior. An approach to the new procedures of verification, validation and certification
- analysis of the electrical behaviour of wind farms facing voltage sags within the new grid codes
- wind Farm Operation as Conventional Power Plant
- spatio-Temporal Effects of Wind and Other RES in Europe.

Sweden

The participating institute is the Royal Institute of Technology, Kungliga Tekniska Högskolan, KTH, in Stockholm. The on-going and planned national projects are related to:

- Development of a tool for analysis of how the trading arrangements affect wind power producers. The tool will take into account the impact of forecast errors between bid submission to delivery hour and imbalance pricing.

- A study of Nordic electricity prices in 2015 assuming that 10 TWh wind power generation is added in Sweden and Norway respectively.
- A study of the influence of large volumes of wind power on the planning and operation of the Nordel system, with focus on international power exchange and the role of the transmission system operator.
- Development of analyzing tools for evaluation of needs for extended transmission in systems with large amounts of wind power.
- Wind power in areas with limited export capabilities. In the actual area it is assumed that there is wind power, other power sources e.g. hydro power and also a load. Within the project the following items are planned to be covered concerning managing of congestion situations: Which methods can be used within a deregulated framework to make hydro power owners interested in balancing wind power? How will uncertain wind speed forecasts affect the possibilities to balance wind power with hydro power? How can grid tariff construction affect the interest of hydro power owners? What are the possibilites to use pumped storage in the hydro system to balance wind power? Can grid extensions also be motivated by the interest to use hydro power as reserve power?
- Hydropower bidding model under significant uncertainty. When the amount of wind power increases in the power system, the uncertainties in the short time operation planning will increase. Models are developed for how to bid power both on the day-ahead market and on the regulating market when the amount of uncertainties, caused by wind power, will increase.

UK

The UK Centre for Sustainable Electricity and Distributed Generation (SEDG) has following areas of work:

- Enhancement of methodologies to analyse system operation and development of systems with large scale penetration of wind considering demand side management, storage and application of smart appliances.
- Assessment of transmission requirements for integration of large scale on- and off-shore wind generation.

- Comprehending the interactions of variable (wind) generation in electricity and energy markets for formulation of appropriate market structures, regulatory regimes and policy measures.

USA

- High wind penetration studies being carried out in both the Eastern Interconnection, and in the WestConnect footprint of the Western Interconnection with the support of NREL. In addition, the Eastern Interconnection study is being conducted in parallel with the Joint Coordinated System Plan (JCSP), a transmission planning effort being carried out by the major eastern RTOs to determine the transmission needs for a 20 % wind energy scenario.
- The impact of stochastic or other advance approaches to unit commitment on wind integration in the U.S.
- MISO transmission expansion planning approach to comprehensive transmission planning methods for energy resources like wind.
- Changes to regional market designs to accommodate higher penetrations of variable output renewable resources.
- Impact of wide area energy management to help integrate wind. Examples include balancing area consolidation or other vehicles to jointly manage the increased variability and uncertainty from wind energy.

Other studies

There is an ongoing activity at CIGRE JWG C1-C2-C6.18 on Coping with limits for very high penetrations of renewable energy.

The study by European TSOs, started in 2006, is in the second phase. The objective of the European Wind Integration Study (EWIS) is to seek proposals for a generic and harmonized European wide approach towards wind energy issues addressing operational and technical aspects including grid connection codes, market organizational arrangements, regulatory and market-related requirements, common public interest issues and even some political aspects impacting the integration of wind energy.

Appendix 2: Detailed review of simulations for case studies

In this Appendix, the review tables from simulations regarding balancing requirements are presented.

Table A. 1 West Denmark

<table>
<tr><td colspan="8">Pedersen, J. & Eriksen, P.B. “System and Market Changes in a Scenario of increased Wind Power Production”</td></tr>
<tr><td colspan="8">Geographic area of study + year(s) studied: Western Denmark, 2005</td></tr>
<tr><td colspan="8">Power system characteristics:</td></tr>
<tr><td colspan="3">Load</td><td>Installed (non-wind) generation</td><td>Inter-connection</td><td colspan="3">Wind power</td></tr>
<tr><td>Peak (MW)</td><td>Min (MW)</td><td>TWh/a</td><td>Capacity (MW)</td><td>Capacity (MW)</td><td colspan="2">MW</td><td>TWh/a</td></tr>
<tr><td></td><td></td><td>26.3</td><td>ca. (5 700-x) with x = simulation result</td><td>0</td><td colspan="2">0…ca 7 200</td><td>0…26.3</td></tr>
<tr><td colspan="8">Power system details: thermal-wind-mixed (5 700-x) MW thermal: ca. (1 500+y) MW gas; ca. (4 000-z) MW coal 0 MW nuclear) (x, y and z are simulation results)</td></tr>
<tr><td colspan="8">Interconnection details: 0 MW</td></tr>
<tr><td colspan="8">Wind power details: geographical distribution: existing plants up to production of 6 TWh onshore, 20 TWh offshore</td></tr>
<tr><td colspan="8">Set up</td></tr>
<tr><td>A</td><td colspan="3">Aim of study</td><td colspan="4">1 what happens with 26.3 TWh wind
(= 100 % of consumption)</td></tr>
</table>

Appendix 2: Detailed review of simulations for case studies

M	**Method to perform study**	1 add wind energy 2 wind also replaces capacity For capacity credit also: a – chronological, using wind power and load profiles
S	**Simulation model of operation**	2 deterministic simulation several cases
Simulation detail		
R	**Resolution of time**	2 hour; DURATION of simulation period: one year
P	**Pricing method**	1 costs of fuels etc 3 perfect market simulation
D	**Design of remaining system**	2 optimized remaining production capacity 4 changed operation due to wind power
Uncertainty and balancing		
I	**Imbalance calculation**	3 wind+load+production outages cause imbalances
B	**Balancing location**	2 from the same region
U	**Uncertainty treatment**	1 transmission margins: 3 wind forecasts: b assume perfect forecast for wind, 5 load forecasts considered: 6 thermal power outages considered: TIME HORIZON for forecasts assumed in the simulation: day-ahead
Power system details		
G	**Grid limit on transmission**	2 constant MW limits
H	**Hydro power modeling**	8 other: no hydro power
T	**Thermal power modeling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered 4 heat production considered
W	**Wind power modeling**	1 time series: b – wind power from wind farms (onshore and offshore) 3 synchronous wind data with load 4 installation scenarios for future wind power distribution (put together scenarios by association, of wind: whole region)

Table A. 2 Sweden / hydro power efficiency

<table>
<tr><td colspan="7">Study conducted by + year when made: Lennart Söder, 1994</td></tr>
<tr><td colspan="7">Geographic area of study + year(s) studied: Sweden (one river system, results upscaled to Sweden)</td></tr>
<tr><td colspan="7">Power system characteristics:</td></tr>
<tr><td colspan="3">Load</td><td>Installed (non-wind) generation</td><td>Inter-connection</td><td colspan="2">Wind power</td></tr>
<tr><td>Peak (MW)</td><td>Min (MW)</td><td>TWh/a</td><td>Capacity (MW)</td><td>Capacity (MW)</td><td>MW</td><td>TWh/a</td></tr>
<tr><td colspan="7">Power system details: hydro</td></tr>
<tr><td colspan="7">Interconnection details: no</td></tr>
<tr><td colspan="7">Wind power details:</td></tr>
<tr><td colspan="7">Characteristics of system planning:</td></tr>
<tr><td colspan="7">Description of market: 0–90 MW of wind power in a 478 MW hydro system consisting of seven linked stations was considered and the results were scaled up to be representative for a hydro system with an installed capacity of 16 400 MW. Perfect information and perfect economic operation was assumed.</td></tr>
<tr><td colspan="7">Integration time frames of importance:</td></tr>
<tr><td colspan="7">Set up</td></tr>
<tr><td>A</td><td colspan="2">Aim of study</td><td colspan="4">1 what happens with x GWh (or y GW) wind
2 how much wind is possible (wind power increased until evaluation strategy did not work)</td></tr>
<tr><td>M</td><td colspan="2">Method to perform study</td><td colspan="4">1 add wind energy
3 load is increased same amount of GWh as wind</td></tr>
<tr><td>S</td><td colspan="2">Simulation model of operation</td><td colspan="4">3 deterministic planning with stochastic wind forecast errors
Deterministic planning but evaluation based on rescheduling every hour based on stochastic forecast errors</td></tr>
<tr><td colspan="7">Simulation detail</td></tr>
<tr><td>R</td><td colspan="2">Resolution of time</td><td colspan="4">2 hour. Several representative days were simulated</td></tr>
<tr><td>P</td><td colspan="2">Pricing method</td><td colspan="4">5 other: The “integration cost” was calculated as needed extra wind energy (MWh) to compensate for lost hydro energy</td></tr>
<tr><td>D</td><td colspan="2">Design of remaining system</td><td colspan="4">1 constant remaining system
6 other: load was increased corresponding to wind increase</td></tr>
</table>

Appendix 2: Detailed review of simulations for case studies

Uncertainty and balancing		
I	**Imbalance calculation**	2 wind+load forecast errors cause imbalance
B	**Balancing location**	1 dedicated source 4 other: Wind power balancing was performed in one river and the result was upscaled to Sweden
U	**Uncertainty treatment**	3 wind forecasts: d best available forecasts, forecast error 2 h … 30 h ahead (RMSE) 1.56 …3.21 m/s in winter and 1.56 …2.70 m/s in summer. 5 load forecasts considered: RMSE 1 h ahead 1 % and 24 h ahead 2 % of peak load For each day 1–24 hour forecasts are used for both wind and load uncertainty.
Power system details		
G	**Grid limit on transmission**	1 no limits
H	**Hydro power modeling**	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 hydrological restrictions included (reservoir level, stream flows) 4 availability of water, capacity factor, dry/wet year 5 hydro optimization considered
T	**Thermal power modeling**	5 other: no thermal power in the system
W	**Wind power modeling**	1 time series: a - measured wind speed + power curve (8 sites) many generated power series based on stochastically generated windspeed forecast errors including generalized dependency

Table A. 3 Nordic hydro efficiency

<table>
<tr><td colspan="7">Study conducted by + year when made: (Holttinen et al., 2001)</td></tr>
<tr><td colspan="7">Geographic area of study + year(s) studied: Nordic countries 2000 and 2010</td></tr>
<tr><td colspan="7">Power system characteristics:</td></tr>
<tr><th colspan="3">Load</th><th>Installed (non-wind) generation</th><th>Inter-connection</th><th colspan="2">Wind power</th></tr>
<tr><th>Peak (MW)</th><th>Min (MW)</th><th>TWh/a</th><th>Capacity (MW)</th><th>Capacity (MW)</th><th>MW</th><th>TWh/a</th></tr>
<tr><td>67 000</td><td>24 000</td><td>385</td><td>90 000</td><td>3 00</td><td>18 000</td><td>46</td></tr>
<tr><td colspan="7">Power system details: thermal-hydro-mixed: hydro 191 TWh/a, nuclear 92 (2010: 89) TWh/a; CHP 60 (2010: 88) TWh/a; thermal condensing 5500 (2010: 7 700) MW</td></tr>
<tr><td colspan="7">Interconnection details: Nordic area is well interconnected within the four countries. Total 1 800 MW DC and 1 200 MW AC links to Central Europe, flexible.</td></tr>
<tr><td colspan="7">Wind power details: distributed over the 4 Nordic countries (11 TWh/a West Denmark, 5 TWh/a East Denmark, 9 TWh/a Norway, 14 TWh/a Sweden (South), 7 TWh/a Finland); no distinction between offshore/onshore nor transmission / distribution network connected in the model</td></tr>
<tr><td colspan="7">Characteristics of system planning: weekly optimization according to water values of hydro power, using 4 load steps during the week</td></tr>
<tr><td colspan="7">Description of market: common Nordic market with possibilities to import/export from/to Central Europe</td></tr>
<tr><td colspan="7">Integration time frames of importance: weekly</td></tr>
<tr><td colspan="7">Set up</td></tr>
<tr><td>A</td><td colspan="2">Aim of study</td><td colspan="4">1 what happens with x GWh wind, increased wind power with remaining system kept the same</td></tr>
<tr><td>M</td><td colspan="2">Method to perform study</td><td colspan="4">1 add wind energy</td></tr>
<tr><td>S</td><td colspan="2">Simulation model of operation</td><td colspan="4">2 deterministic simulation, 30 different hydro inflow cases</td></tr>
<tr><td colspan="7">Simulation detail</td></tr>
<tr><td>R</td><td colspan="2">Resolution of time</td><td colspan="4">1 week (with 4 load profiles, hydro inflow and wind assumed constant during the week), duration of simulation period: 30 years</td></tr>
<tr><td>P</td><td colspan="2">Pricing method</td><td colspan="4">1 costs of fuels etc. Pricing from market simulation (demand and supply curves)</td></tr>
<tr><td>D</td><td colspan="2">Design of remaining system</td><td colspan="4">1 constant remaining system
4 changed operation due to wind power</td></tr>
</table>

Appendix 2: Detailed review of simulations for case studies

Uncertainty and balancing		
I	**Imbalance calculation**	no imbalance calculation, weekly resolution
B	**Balancing location**	no imbalance calculation, weekly resolution
U	**Uncertainty treatment**	2 hydro inflow uncertainty: 3 no wind forecasts (assume persistence), some wind uncertainty taken into account through weekly uncertainty in water value calculations 6 thermal power outages considered:
Power system details		
G	**Grid limit on transmission**	2 constant MW limits both inside the whole area and outside the simulated area
H	**Hydro power modeling**	1 head height considered 2 hydrological coupling included (including reservoir capacity) 3 hydrological restrictions included (reservoir level, stream flows) 4 availability of water, capacity factor, dry/wet year 5 hydro optimization considered
T	**Thermal power modeling**	only availability considered, no detailed modeling (weekly)
W	**Wind power modeling**	1 few wind speed time series (weekly), 30 years of weekly wind data derived from wind speed measurements, 1–2 wind series per country

Table A. 4 Nordic/Germany

<table>
<tr><td colspan="7">Study conducted by + year when made: Risoe National Laboratory, 2006</td></tr>
<tr><td colspan="7">Geographic area of study + year(s) studied: Power system consisting of Denmark, Finland, Germany, Norway and Sweden, divided into 12 regions, 2010 power system scenario, 3 wind power cases</td></tr>
<tr><td colspan="7">Power system characteristics:</td></tr>
<tr><th colspan="3">Load</th><th>Installed (non-wind) generation</th><th>Inter-connection
To outside model area</th><th colspan="2">Wind power</th></tr>
<tr><th>Peak (MW)</th><th>Min (MW)</th><th>TWh/a</th><th>Capacity (MW)</th><th>Capacity (MW)</th><th>MW</th><th>TWh/a</th></tr>
<tr><td>155 500</td><td>65 600</td><td>977</td><td>196 000</td><td>6 600</td><td>Case dep</td><td>Case</td></tr>
<tr><td colspan="7">Power system details: mixed (57 500 MW hydro including pumped hydro storage, 138 500 MW thermal: 31 000 MW gas 36 000 MW coal 32 000 MW nuclear)</td></tr>
<tr><td colspan="7">Interconnection details: Transmission capacity between model regions: 3 120 MW DC, 28 000 MW AC links, the usage of transmission capacity is co-optimised with the usage of production capacity in the study, i.e. very flexible usage of transmission, model decides on the distribution of transmission capacity used for reserves and used for the day-ahead market. Usage of transmission more flexible than in the real power system.</td></tr>
<tr><td colspan="7">Wind power details: geographical distribution: distributed into 12 model regions with wind power production time series reflecting geographical smoothing, Base wind case: 5 500 MW offshore, 30 000 MW on-shore, 10 % wind case: 11 500 MW offshore, 46 000 MW onshore, 20 % wind case: 11 500 MW offshore, 64 000 MW onshore. Distribution network not treated in the study i.e. no difference between connection to transmission network or distribution network</td></tr>
<tr><td colspan="7">Characteristics of system planning: Transmission capacity planning done by TSOs. Investments in power plants decided by power producers. Day-to-day operation of power plants planned by power producers that trade on power pools, sell heat to district heating networks, and sell system services to TSOs.</td></tr>
<tr><td colspan="7">Description of market: Day-ahead spot market (Nord Pool in the Nordic countries, EEX in Germany), also a lot of bilateral power trade. Reserve power markets organized by TSOs.</td></tr>
<tr><td colspan="7">Integration time frames of importance: activation of regulating power (10–15 minutes), unit commitment (hours)</td></tr>
</table>

Appendix 2: Detailed review of simulations for case studies

Set up		
A	**Aim of study**	1 what happens with x GWh (or y GW) wind
M	**Method to perform study**	1 add wind energy – comparison between stochastic, variable wind production and equivalent predictable, constant wind production
S	**Simulation model of operation**	4 Stochastic simulation several cases
Simulation detail		
R	**Resolution of time**	2 hour. DURATION of simulation period: one year.
P	**Pricing method**	1 cost of fuels, including star-up costs 3 perfect market simulation (each actor maximizes its benefit according to some definition considering the physical and legal constraints)
D	**Design of remaining system**	1 constant remaining system 4 changed operation due to wind power 5 perfect trading rules
Uncertainty and balancing		
I	**Imbalance calculation**	1 only wind cause imbalances - for reserve power allocation wind forecast errors and production outages are combined
B	**Balancing location**	3 also outside region
U	**Uncertainty treatment**	2 hydro inflow uncertainty: 3 wind forecasts: d best available forecasts, standard deviation of wind power production forecast error equal to 15–18 % of installed wind power capacity for forecast horizons 8–36 hours ahead, lower for shorter forecast horizons. TIME HORIZON for forecasts 3–36 hours ahead
Power system details		
G	**Grid limit on transmission**	2 constant MW limits, limits inside the whole area: 31 000 MW, limits outside the simulated area: 6 600 MW
H	**Hydro power modeling**	3 hydrological restrictions included (reservoir level, stream flows) 4 availability of water, capacity factor, dry/wet year 5 hydro optimization considered
T	**Thermal power modeling**	2 start/stop costs considered (linear approximation) 3 efficiency variation considered (linear approximation) 4 heat production considered

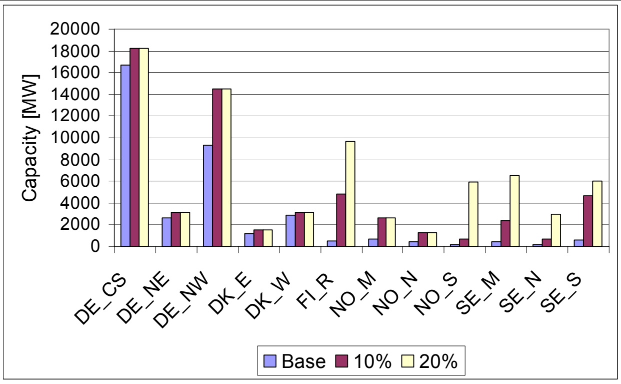
W	**Wind power modeling**	 **Figure: Geographical distribution of installed wind power capacity.** Denmark: Historical hourly, total wind power production data for East and West Denmark. Finland: Historical hourly wind power production time series for 21 sites. Germany: Historical hourly wind speed time series for 10 sites. Norway: Historical hourly wind speed time series for 6–12 sites. Sweden: Historical hourly wind power production time series for 6 sites. d – time series smoothing considered (aggregation of time series from different sites into one time series for each model region) 3 synchronous wind data with load 4 installation scenarios for future wind power distribution (put government plans combined with expert judgement and wind power projects applying for planning permits)

Table A. 5 USA Minnesota 2004

<table>
<tr><td colspan="8">Study conducted by + year when made: EnerNex/WindLogics, 2004</td></tr>
<tr><td colspan="8">Geographic area of study + year(s) studied: Minnesota, 2010</td></tr>
<tr><td colspan="8">Power system characteristics:</td></tr>
<tr><td colspan="3">Load</td><td>Installed (non-wind) generation</td><td>Inter-connection</td><td colspan="3">Wind power</td></tr>
<tr><td>Peak (MW)</td><td>Min (MW)</td><td>TWh/a</td><td>Capacity (MW)</td><td>Capacity (MW)</td><td colspan="2">MW</td><td>TWh/a</td></tr>
<tr><td>9 933</td><td>3 00</td><td>48.1</td><td>11 426</td><td>1 500</td><td colspan="2">1 500</td><td>5.8</td></tr>
<tr><td colspan="8">Power system details: thermal-hydro-mixed (App. 2 % hydro; 28 % gas; 25 % coal; 12 % nuclear; 4 % oil, 21 % short and long term purchases; 8 % other, including wood, biomass, wind at 13.5 % capacity factor)</td></tr>
<tr><td colspan="8">Interconnection details: Transmission not explicitly modeled; no DC ties, some purchases via transmission ties, self provides regulation/reserves</td></tr>
<tr><td colspan="8">Wind power details: wind plants well distributed over a 1,000 km square, all on-shore, all assumed transmission connected.</td></tr>
<tr><td colspan="8">Characteristics of system planning: Assumed vertically integrated utility environment for thermal system, with wind plants built in response to an RPS</td></tr>
<tr><td colspan="8">Description of market: Bilateral trading</td></tr>
<tr><td colspan="8">Integration time frames of importance: Regulation, load following, unit commitment</td></tr>
<tr><td colspan="8">Set up</td></tr>
<tr><td>A</td><td colspan="2">Aim of study</td><td colspan="5">1 what happens with x GWh (or y GW) wind</td></tr>
<tr><td>M</td><td colspan="2">Method to perform study</td><td colspan="5">1 add wind energy
For capacity credit: a – chronological, using wind power and load profiles</td></tr>
<tr><td>S</td><td colspan="2">Simulation model of operation</td><td colspan="5">2 deterministic simulation several cases</td></tr>
<tr><td colspan="8">Simulation detail</td></tr>
<tr><td>R</td><td colspan="2">Resolution of time</td><td colspan="5">1 day/week
2 hour
DURATION of simulation period: 3 one-year periods</td></tr>
<tr><td>P</td><td colspan="2">Pricing method</td><td colspan="5">1 costs of fuels etc</td></tr>
<tr><td>D</td><td colspan="2">Design of remaining system</td><td colspan="5">1 constant remaining system</td></tr>
</table>

Uncertainty and balancing		
I	**Imbalance calculation**	3 wind+load+production outages cause imbalances
B	**Balancing location**	2 from the same region
U	**Uncertainty treatment**	1 transmission margins: not considered 2 hydro inflow uncertainty: deterministic 3 wind forecasts: (d best available forecasts, app. 20 % MAE) 5 load forecasts considered: yes 6 thermal power outages considered: yes 7 other: TIME HORIZON for forecasts assumed in the simulation (day-ahead)
Power system details		
G	**Grid limit on transmission**	1 no limits
H	**Hydro power modeling**	6 limited, deterministic run-of-river 7 interaction with hydro resources not significant
T	**Thermal power modeling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered
W	**Wind power modeling**	1 time series: c - re-analysis wind speed + power curve (50 sites) 2 wind power profiles (b – hour of day) 3 synchronous wind data with load 4 installation scenarios for future wind power distribution based on knowledge of local developments with assistance of wind association in 1,000 km square region

Table A. 6 USA Minnesota 2006

<table>
<tr><td colspan="7">Study conducted by + year when made: EnerNex/WindLogics, 2006</td></tr>
<tr><td colspan="7">Geographic area of study + year(s) studied: Minnesota, 2020</td></tr>
<tr><td colspan="7">Power system characteristics: (Area of Minnesota included in study)</td></tr>
<tr><td colspan="3">Load</td><td>Installed (non-wind) generation</td><td>Inter-connection</td><td colspan="2">Wind power</td></tr>
<tr><td>Peak (MW)</td><td>Min (MW)</td><td>TWh/a</td><td>Capacity (MW)</td><td>Capacity (MW)</td><td>MW</td><td>TWh/a</td></tr>
<tr><td>21 000</td><td>8 800</td><td>85</td><td>23 500</td><td>5 000</td><td>5 700</td><td>21</td></tr>
<tr><td colspan="7">Power system details: thermal-hydro-mixed, MISO percentages (3.5 % hydro, 6 % renewables, 90.5 % thermal: 23.5 % gas, 5 % oil, 55 % coal, 7 % nuclear)</td></tr>
<tr><td colspan="7">Interconnection details: The Minnesota system is part of the MISO market and the NERC Midwest Reliability Organization (MRO), which is a part of the larger Eastern Interconnection. Minnesota is estimated to have approximately 5,000 MW of interconnection capacity in place by 2020. Part of Minnesota load is regularly supplied by generation from out of state.</td></tr>
<tr><td colspan="7">Wind power details: The 5,700 MW of wind capacity in 2020 is onshore, spread in four regions of a 3 state area with good regional diversity, in a square of approximately 750 km per side, all transmission connected, with minimal transmission congestion.</td></tr>
<tr><td colspan="7">Characteristics of system planning: Assumed vertically integrated utility environment for thermal system capacity planning purposes, operating in a market environment for dispatch purposes, with wind plants built in response to an RPS.</td></tr>
<tr><td colspan="7">Description of market: The Minnesota load is served from the MISO market, made up of parts of 14 states in the Upper Midwest region of the US. MISO operates a day-ahead market, hour-ahead market, and is in the process of implementing an ancillary services market. The market currently consists of 116 GW of load, and 133 GW of generation, which is assumed to grow to approximately 170 GW of generation by 2020.</td></tr>
<tr><td colspan="7">Integration time frames of importance: regulation, load following, unit commitment</td></tr>
<tr><td colspan="7">Set up</td></tr>
<tr><td>A</td><td colspan="2">Aim of study</td><td colspan="4">1 what happens with x GWh of wind</td></tr>
<tr><td>M</td><td colspan="2">Method to perform study</td><td colspan="4">1 add wind energy
For capacity credit also: a – chronological, using wind power and load profiles</td></tr>
<tr><td>S</td><td colspan="2">Simulation model of operation</td><td colspan="4">2 deterministic simulation several cases</td></tr>
</table>

Simulation detail		
R	**Resolution of time**	1 day/week 2 hour DURATION of simulation period: 3 periods of 1 year each
P	**Pricing method**	1 costs of fuels etc
D	**Design of remaining system**	4 changed operation due to wind power 5 perfect trading rules 6 other: added additional generation and transmission capacity in accord with current plans, as expressed most clearly in CapX 2020
Uncertainty and balancing		
I	**Imbalance calculation**	3 wind+load+production outages cause imbalances
B	**Balancing location**	2 from the same region 3 also outside region
U	**Uncertainty treatment**	1 transmission margins: honor constraints 2 hydro inflow uncertainty: deterministic 3 wind forecasts: (d. best available forecasts, 20 % MAE of rated capacity day ahead) 5 load forecasts considered: yes 6 thermal power outages considered: yes TIME HORIZON for forecasts assumed in the simulation (hour ahead and day-ahead)
Power system details		
G	**Grid limit on transmission**	2 constant MW limits
H	**Hydro power modeling**	6 limited, deterministic run-of-river 7 interaction with hydro resources not significant
T	**Thermal power modeling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered
W	**Wind power modeling**	1 time series: c – re-analysis wind speed + power curve 2 wind power profiles (b – hour of day) 3 synchronous wind data with load 4 installation scenarios for future wind power distribution (based on detailed wind resource maps and knowledge of local developments, with assistance of stakeholders); specify geographical distribution of wind covers square of 750 km per side.

Table A. 7 Ireland ESBNG

Study conducted by + year when made: ESB National Grid (now EirGrid), 2004						
Geographic area of study + year(s) studied: Republic of Ireland						
Power system characteristics: Republic of Ireland electricity system, 2 different peak loads analysed – 50 00MW and 65 00MW						
Load			**Installed (non-wind) generation**	**Inter-connection**	**Wind power**	
Peak (MW)	**Min (MW)**	**TWh/a**	**Capacity (MW)**	**Capacity (MW)**	**MW**	**TWh/a**
5 000/ 6 500		29/ 38.5	5 732/ 7 354	not considered	0/500/ 1 000/ 1 500/ 2 500/ 3 500	5.2/ 10.5/ 15.7/ 19.6/ 27.4
Power system details: thermal-hydro-mixed (5 000 MW peak system: 544 MW hydro 4 935 MW thermal: 3 769 MW gas 855 MW coal 344 MW peat; 6 500 MW peak system: 544MW Hydro, 6 650 MW Thermal: 5 153 MW gas 855 MW coal 344MW peat)						
Interconnection details: Interconnection not considered for this study.						
Wind power details: Distributed over the whole country, based on 67 % onshore and 33 % offshore.						
Characteristics of system planning: Grid System is centrally planned						
Description of market: None specified – cost based study						
Integration time frames of importance: Unit Commitment time frame						

Set up		
A	**Aim of study**	1 what happens with x GWh (or y GW) wind 3 other: impact of Wind Power on operation of conventional plant
M	**Method to perform study**	2 wind replaces existing capacity, while maintaining system adequacy For capacity credit also: a – chronological, using wind power and load profiles
S	**Simulation model of operation**	2 deterministic simulation, with unit commitment and dispatch, for 2 scenarios, each with four different amounts of wind on the system
Simulation detail		
R	**Resolution of time**	1 hourly, for duration of 1 year
P	**Pricing method**	1 costs of fuels 5 other: additional reserve capital costs attributable to wind energy calculated

D	**Design of remaining system**	1 for 5 000 MW peak load scenario, existing plant with plant dropped as various levels of wind added For 6 500 MW system peak load scenario, most older plant is assumed to have been replaced and augmented by a mixture of Combined Cycle (CC) and Combustion Turbine (CT) units
Uncertainty and balancing		
I	**Imbalance calculation**	4 other: wind + production outages cause imbalances.
B	**Balancing location**	2 from the same region
U	**Uncertainty treatment**	3 wind forecasts: average value of wind over the 24 hour period was used as the forecasted value for commitment algorithm, with variations above or below this used for dispatch algorithm 6 thermal power outages considered: both scheduled and forced outages considered
Power system details		
G	**Grid limit on transmission**	1 no limits
H	**Hydro power modeling**	8 other: hydro plant operating in accordance with historical production profiles
T	**Thermal power modeling**	1 ramp rates considered 2 start/stop costs considered
W	**Wind power modeling**	1 time series: b – Wind Power Profiles. On-shore time series based on 18 existing wind farms, mainly in the south-west and north-west of the country. Offshore time series based on power output of proposed off-shore site in the East of the country 2 wind power profiles b – hour of day 3 wind data not synchronous with load 4 installation scenarios for future wind power distribution according to projected regional capacity factors; on-shore mainly sited in south-west and north-west of country

Table A. 8 Ireland SEI

<table>
<tr><td colspan="7">Study conducted by + year when made: Ilex, UMIST, UCD, QUB, 2004</td></tr>
<tr><td colspan="7">Geographic area of study + year(s) studied: Ireland, 2006 and 2010</td></tr>
<tr><td colspan="7">Power system characteristics: Irish electricity system, consisting of Republic of Ireland and Northern Ireland</td></tr>
<tr><th colspan="3">Load</th><th>Installed (non-wind) generation</th><th>Inter-connection</th><th colspan="2">Wind power</th></tr>
<tr><th>Peak (MW)</th><th>Min (MW)</th><th>TWh/a</th><th>Capacity (MW)</th><th>Capacity (MW)</th><th>MW</th><th>TWh/a</th></tr>
<tr><td>6 127/
6 900</td><td>2 192/
2 455</td><td>35.5/
39.7</td><td>8 110/
8 900</td><td>500/
900</td><td>845/
1 300/
1 950</td><td>2.2/
3.4/
5.1</td></tr>
<tr><td colspan="7">Power system details: Mixed (217.5 MW Hydro, 292 MW pumped hydro storage, 7 488 MW thermal (4 932 MW gas, 345.6 MW peat, 1 215MWcoal, 995.4MW oil)</td></tr>
<tr><td colspan="7">Interconnection details: 500MW HVDC interconnection to Scotland; Planned 400MW Interconnector to England used for 2010 scenarios</td></tr>
<tr><td colspan="7">Wind power details: Wind power distributed over the whole island, 10 % off shore, remainder onshore, 50 % transmission network connected, 40 % distribution</td></tr>
<tr><td colspan="7">Characteristics of system planning: Grid System is centrally planned</td></tr>
<tr><td colspan="7">Description of market: None specified – cost based study</td></tr>
<tr><td colspan="7">Integration time frames of importance: Seconds to 4 hours</td></tr>
<tr><td colspan="7">Set up</td></tr>
<tr><td>A</td><td colspan="2">Aim of study</td><td colspan="4">1 what happens with x GW wind?
3 other: impact of wind on operating reserve</td></tr>
<tr><td>M</td><td colspan="2">Method to perform study</td><td colspan="4">1 add wind energy
capacity credit calculated using wind power and load profiles</td></tr>
<tr><td>S</td><td colspan="2">Simulation model of operation</td><td colspan="4">2 deterministic simulation, for three different cases: winter peak day, summer valley day and shoulder business day</td></tr>
<tr><td colspan="7">Simulation detail</td></tr>
<tr><td>R</td><td colspan="2">Resolution of time</td><td colspan="4">half hourly data
Duration: 1 day</td></tr>
<tr><td>P</td><td colspan="2">Pricing method</td><td colspan="4">1 costs of fuels</td></tr>
<tr><td>D</td><td colspan="2">Design of remaining system</td><td colspan="4">1 constant remaining system, with new CCGTs and OCGTs added to replace retired plant</td></tr>
</table>

Uncertainty and balancing		
I	**Imbalance calculation**	3: wind + load + production outages cause imbalances
B	**Balancing location**	2 from the same region – all reserve is provided on the island
U	**Uncertainty treatment**	3 wind forecasts: d best available forecasts for wind assumed, standard deviation of error increases as forecast horizon increases (14–18 % for 1–8 hours ahead) 5 load forecasts considered: Defined for different timeframes – 1 hour – 40 MW, 4 hours – 60 MW 6 thermal power outages considered: both scheduled and forced outages considered 7 wind and load forecast errors are combined for different time horizons TIME HORIZON for forecasts assumed in simulation: 1 and 4 hours
Power system details		
G	**Grid limit on transmission**	1 no limits
H	**Hydro power modeling**	8 other: hydro plant operating in accordance with historic profiles
T	**Thermal power modeling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered
W	**Wind power modeling**	1 time series: b - wind energy time series for future years was produced based on historical data from 10 wind farms, and scaled appropriately 2 wind power profiles b – hour of day 3 wind data not synchronous with load 4 installation scenarios for future wind power distribution according to projected regional capacity factor, distributed across the country

Table A. 9 Netherlands

Study conducted by: Bart C. Ummels. Delft University of Technology, 2008

Geographic area of study: NL with interconnections to B, F, D, UK, NOR, year 2014

Power system characteristics:

Load			**Installed (non-wind) generation**	**Inter-connection**	**Wind power**	
Peak (MW)	**Min (MW)**	**TWh/a**	**Capacity (MW)**	**Capacity (MW)**	**MW**	**TWh/a**
21 000	**10 500**	**126**	**30 000**	**7 350**	**0–12**	**0–43**

Power system details: Thermal-hydro-mixed

Technology	Netherlands [GW]	Belgium [GW]	France [GW]	Germany [GW]	GB [GW]	*Norway [GW]*
Nuclear	0.4	5.9	64.9	14.1	11.9	–
Coal	9.5	2.6	6.0	32.0	30.4	–
Lignite	–	–	–	18.9	–	–
CCGT CHP Ind.	4.0	–	–	–	–	–
BF Gas Ind.	0.9	–	–	–	–	–
CCGT CHP Res.	1.5	–	–	–	–	–
CCGT	7.1	5.0	4.0	15.1	24.4	–
Gas Turbine	0.6	1.5	1.1	4.0	7.0	–
Oil	–	–	9.2	5.3	8.4	–
Reservoir Hydro	–	–	13.6	3.7	1.8	–
Pumped Hydro	–	1.3	4.2	5.5	3.0	*0.7*
RoR Hydro	–	0.1	7.9	–	–	–
Other	6.3	0.4	–	8.2	–	–
Total	30.4	16.8	110.9	106.8	86.9	*0.7*
Wind Power	10.0	–	–	32.0	–	–
Maximum Load	21.0	15.2	80.5	87.1	65.5	–
Demand [TWh/y]	126	97	518	550	367	–

Table 4.2: Generation technologies per country in 2014.

Interconnection details: International exchange: none, 24 h. market closure based on perfect market using best available wind forecast, idem for 3 h ahead; idem for 1 h. ahead. Reserves are defined for each separate area (NODE is only to take into account net import capacity of the Netherlands, while there can be transits between Belgium and Germany

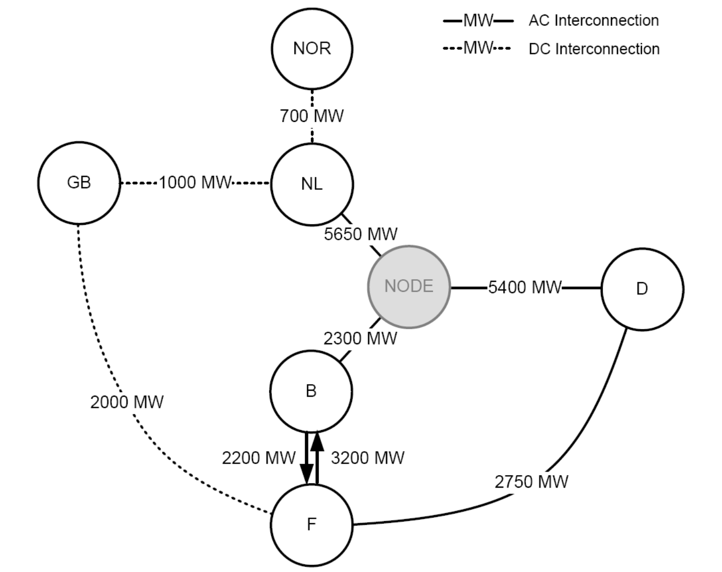
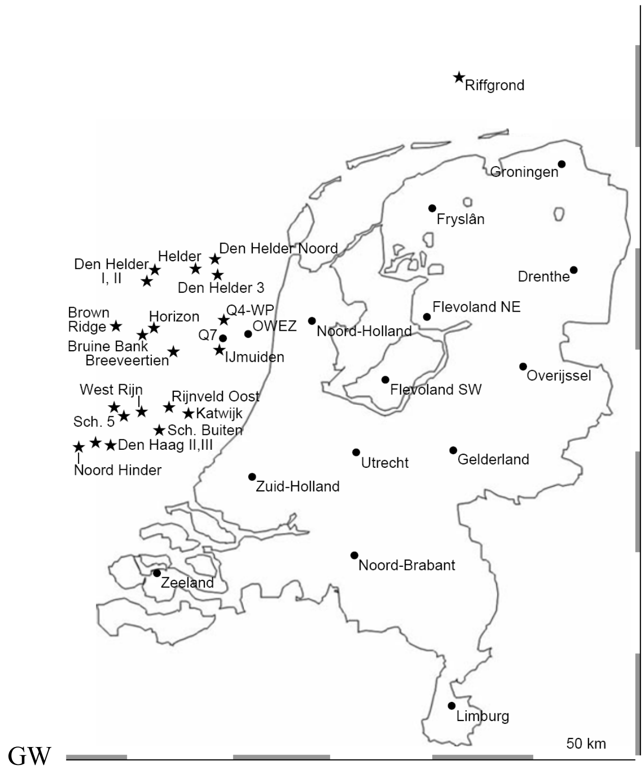


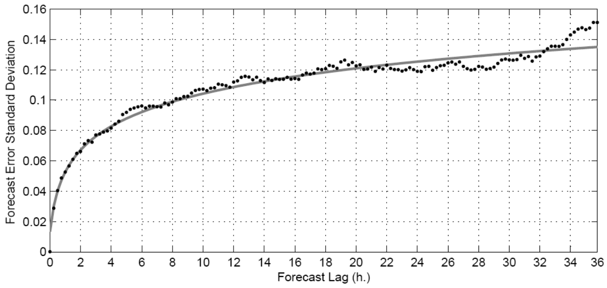
Figure 4.2: Areas and interconnections included in the simulation model.

I

Wind power details: Onshore 0–4 GW, Offshore 0–8



<table>
<tr><td colspan="3">Characteristics of system planning: None; only adequacy forecast of Dutch TSO for 2014 is used. Installed capacity in neighbouring countries is estimated based on forecasts of UCTE and National Grid.</td></tr>
<tr><td colspan="3">Description of market: Internally in areas: perfect market. Four different international market designs, from no exchange to fully flexible</td></tr>
<tr><td colspan="3">Integration time frames of importance: 24 h. ahead – 3 h. ahead – 1 h. ahead – real-time wind power output</td></tr>
<tr><td colspan="3">Set up</td></tr>
<tr><td>A</td><td>Aim of study</td><td>1 what happens with 43 000 GWh (or 12 GW) wind
2 how much wind is possible (no maximum – just wasted wind)</td></tr>
<tr><td>M</td><td>Method to perform study</td><td>1 add wind energy
No capacity credit used – increasing wind power and looking at technical impacts</td></tr>
<tr><td>S</td><td>Simulation model of operation</td><td>5 Probabilistic, chronological simulation, single wind power forecast, hourly wind power updates</td></tr>
<tr><td colspan="3">Simulation detail</td></tr>
<tr><td>R</td><td>Resolution of time</td><td>15 min. simulation time-step, weekly uptimisation, yearly simulation</td></tr>
<tr><td>P</td><td>Pricing method</td><td>1 costs of fuels etc
3 perfect market simulation (each actor maximizes its benefit according to some definition considering the physical and legal constraints)</td></tr>
<tr><td>D</td><td>Design of remaining system</td><td>1 constant remaining system
4 changed operation due to wind power</td></tr>
<tr><td colspan="3">Uncertainty and balancing</td></tr>
<tr><td>I</td><td>Imbalance calculation</td><td>3 wind+load+production outages cause imbalances</td></tr>
<tr><td>B</td><td>Balancing location</td><td>2 from the same region
3 also outside region</td></tr>
<tr><td>U</td><td>Uncertainty treatment</td><td>1 transmission margins (DC transmission outages):
3 wind forecasts (all of these): (a assume no knowledge and large margins for wind 0…full capacity b assume perfect forecast for wind, c persistence forecasts for wind d best available forecasts, specify what level of forecast error assumed)
6 thermal power outages considered:</td></tr>
</table>

		 Figure 2.14: Normalised standard deviation of wind power forecast error for 12 GW wind power.
Power system details		
G	**Grid limit on transmission**	2 constant MW limits
H	**Hydro power modeling**	1 head height considered 4 availability of water 5 hydro optimization considered 6 limited, deterministic run-of-river 7 interaction with hydro resources not significant The use of the available water (average water level for each week) is optimised based on costs during the week. For specifically modeled pumped hydro in the Netherlands, head heights and reservoir limits are taken into account.
T	**Thermal power modeling**	1 ramp rates considered 2 start/stop costs considered 3 efficiency variation considered 4 heat production considered 5 combined heat and power considered
W	**Wind power modeling**	1 time series: a - measured wind speed + power curve from 38 future wind farms at designated locations d – time series smoothing considered (linear interpolation between sites) 3 wind data synchronous with load only for day of year (i.e. different years of wind speed data and load data) 4 installation scenarios for future wind power distribution (put together scenarios by permit requests and; according to projected regional capacity

Appendix 3: Terminology for short term operational reserves in Europe

(Söder et al., 2006)

Appendix 3: Terminology for short term operational reserves in Europe (Söder et al., 2006)

OVERALL	DETAIL	UNIT	SUPRANATIONAL ASSOCIATIONS			NATIONAL					
			UCTE	NORDEL	DC Baltija	Belgium	France	Germany	Great Britain	Netherlands	Poland
LOAD-FREQUENCY AND RESERVES CONTROL	**Primary (Spinning)**		**Primary Control**			**Primary Control**	**Primary Control**	**Primary Control**	**Contingency & Operating Reserves, Primary Response**	**Primary Reserve**	
	Reference		OH: Policy 1 & Appendix 1: Load-Frequency Control and Performance, A. Primary Control	NGC-Appendix 2 of System Operation Agreement	GC, Sec. 2.1.2	Titre IV Chapter XIII, Art 236 to 242	INDI0301719A: Chapter III, Art 11,Primary reserve must be >/= 2.5% of capacity for generating plant > 40MW. Référentiel Technique: Chapitre 4.1.	TC Section 2.3.6, section 2.3.7 and Appendix D 3.1.	Grid Code: CC.A.3.2, BC 1.5.4 and BPS	NetCode 5.1.1.1.a.1 and System Code 2	
	Definition		Stabilises frequency, although the level may differ from the set point and border power exchanges may be altered.	Stabilises frequency, although the level may differ from the set point and border power exchanges may be altered.	The definition of primary control reserves on page 12 is "- a second reserve of active power used for frequency control."		INDI0301719A: Chapter III, Art 11,Primary reserve response such that for frequency drop of >/= 200mHz, restoration of primary reserve in < 30s and half this in < 15s.	Generating units > 100MW must be capable of delivery of primary response as per TC Figs 2.1 & 2.2	Operating Reserve comprises Reserve for Response and Short-Term Reserve	System Code 2.1.13 and Appendix 3 presents the voltage/ frequency U/f charts, power output levels and durations	
	Governor Mode		Governor control of all generators subject to primary control	Governor control of all generators subject to primary control. Load shedding allowed for f=49.5-49.9 Hz	Governor control of all generators subject to primary control	Art 236 requires automatic control of primary reserve		Governor control of all generators subject to primary control, =/- 2% of rated output	Some generation in Frequency Sensitive Mode, other in Limited Frequency Sensitive Mode	SystemCode 2.2.20 and Imple-mentation Regulations 1.3.4	
	Speed of response		Primary Control Power to increase linearly up to 3000MW over 30s	Primary Control Power to increase linearly up to 3000MW over 30s	Ramp rate no less than 2.5% of the rated power in 5 sec. and 5% in 30 sec.; hydrogenerators and turbogenerators must be able to maintain the varied power at frequency deviation for at least 15 min.; primary control power must be available repeatedly after 10 min. of the previous attempt;	Art 242 requires 50% of primary reserve to be provided within 15s of the start of the frequency deviation with the remainder following between 15s and 30s of the start.		TC 2.3.7.1, up to 30s	Primary Response ramps from 0 to 10s, effective for another 20s	System Code 2.1.6 and Appendix 2 , up to 30s @ 7% per minute	
	Maximum load loss		Up to 3000MW load loss without load shedding; maximum permissible dynamic frequency deviation 800mHz	Up to 600 MW load loss without load shedding; maximum permissible dynamic frequency deviation 100mHz	Loss of generator transformer block up to 750 MW, bus as well as busbar of total generating power under 600 MW; loss of loas up to 250 MW; frequency should not deviate by more than 0.5 Hz				For 300 to 1000MW power loss, frequency should not deviate by > 0.5Hz	Tennet: Imple-mentation Regulation 1.3 describes regulating, reserve and emergency power categories.	
	Self regulation		Self regulation of load (MW/Hz) taken into account	Self regulation of load (MW/Hz) taken into account. Load decrease of 200 MW at 49.5 Hz assumed	Not considered in grid code. It can here be noted that DC Baltija is strongly and synchronously connected to Russia and Belorus, so all items concerning frequency control is not a responsibility of DC Baltija				Response requirement (MW) calculated by NGC every half-hour and determined according to load conditions	Self regulation of load (MW/Hz) taken into account	
	Contribution		Primary control shared between Control Areas according to contribution coefficients	Primary control shared between four countries according to yearly consumption and dimensioning faults	Primary control shared between Control Areas and is set up to 5% depending on max load of the Control Area in the previous period				Reserve standard is LOLE of 1 event per annum, a 1 in 365 expectation.	Tennet: Estimated primary reserve contribution for 2005 is 109MW i.e. 3.6% of UCTE total.	

Appendix 3: Terminology for short term operational reserves in Europe
(Söder et al., 2006)

OVERALL	DETAIL	UNIT	SUPRANATIONAL ASSOCIATIONS			NATIONAL					
			UCTE	NORDEL	DC Baltija	Belgium	France	Germany	Great Britain	Netherlands	Poland
	Secondary (spinning and non-spinning)		**Secondary Control**		Secondary control	**Secondary Control**	**Secondary Control**	**Secondary Control**	**Contingency & Operating Reserves, Secondary Response**	**Secondary Regulation**	
	Reference		OH: Policy 1 & Appendix 1: Load-Frequency Control and Performance, B. Secondary Control	NGC-Appendix 2 of System Operation Agreement	Section 2.1.3	Titre IV Chapter XIII, Art 243 to 247	INDI0301719A: Chapter III, Art 12 Référentiel Technique: Chapitre 4.1.	TC Section 2.3.7 and Appendix D 3.2	GC: CC.A.3, BC 1.5.4 and BPS	Tennet: Summary of current operating principles of UCTE, sections 3 & 5.	
	Control mechanism		Automatic Generator Control, to restore power exchanges to set point value	No Automatic Generator Controll Bids from regulating market called when needed	Automatic Generator Control, to restore power exchanges to the preset value	Art 246 The system operator determines the amount of secondary reserve that each generator is to put at the disposal of the system operator.	INDI0301719A: Chapter III, Art 12, any generating group > 120MW must have a half-band of secondary reserve > 4.5% of rating.	TC Appendix D 3.2.1 and 3.2.2.6 - automatic control by Regulating Zone using central secondary automatic controller	Short Term Reserve comprises Standing Reserve and Regulating Reserve (latter includes Fast Reserve)		
			Controls Area Control Error (ACE) to zero	Cheapest bids in the whole area accepted as long as transmission limits are not violated	Area Control Error not considered in Grid Code	Art 248 The system operator is to determine the unbalance with the foreign regulating zones		Load frequency controller for German control unit is located in Brauweiler near Cologne and is operated by RWE	Operations under instruction		
	Response		30s to 15 mins	Available in 10 mins. Disturbance reserves available within 15 minutes	30s to 15 mins			TC Appendix D 3.2.1 - entire contracted secondary response to be available in 5 minutes	30s to 30 minutes		
			Amount of reserve quantified by formula according to demand, by Control Area	No formal requirements of total reserves, but the TSO:s have extra reserves for disturbance situations	Requirements for secondary reserves for Control Areas (each country = 1 TSO = one CA) and the control Block are set according to methodology approved by the Operators and control block operator.				Response requirement (MW) calculated by NGC every half-hour and determined according to load conditions		
	Capacity		Each Control Area to have sufficient control of generation or load control to control ACE to zero.	Cheapest bids in the whole area accepted as long as transmission limits are not violated	No requirements of specific amount of control in each area. At least not in the grid code.			TC Appendix D 3.2.2.- each generating unit providing secondary response must be able to provide +/- 30 MW.			
	Tertiary		**Tertiary Control**		**Tertiary control**	**Tertiary Reserve**	**Tertiary Control**	**Minute Reserve**		**Emergency Power**	
	Reference		OH: Policy 1 & Appendix 1: Load-Frequency Control and Performance, C. Tertiary Control	NGC-Appendix 2 of System Operation Agreement	Section 2.1.4	Titre IV Chapter XIII, Art 249 to 256		TC Appendix D 3.3		Dte: SystemCode 2.2.5b and Tennet: Operations - Managing Concept 5.8	
	Control mechanism		Activated manually by TSOs	Included in secondary control	Few details concerning treatment of tertiary control	Procured through competitive bidding		Contract with ÜNB			
	Purpose		Frees up Secondary Reserves		Frees up Secondary Reserves			Frees up Secondary Reserves			
	Response		15 minute reserve		Is carried out in every control area			15 minute reserve		To be available in 30 mins	

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Author(s)
Hannele Holttinen, Peter Meibom, Antje Orths, Frans van Hulle, Bernhard Lange, Mark O'Malley, Jan Pierik, Bart Ummels, John Olav Tande, Ana Estanqueiro, Manuel Matos, Emilio Gomez, Lennart Söder, Goran Strbac, Anser Shakoor, João Ricardo, J. Charles Smith, Michael Milligan & Erik Ela

Title

Design and operation of power systems with large amounts of wind power
Final report, IEA WIND Task 25, Phase one 2006–2008

Abstract
There are already several power systems coping with large amounts of wind power. High penetration of wind power has impacts that have to be managed through proper plant interconnection, integration, transmission planning, and system and market operations. This report is a summary of case studies addressing concerns about the impact of wind power's variability and uncertainty on power system reliability and costs. The case studies summarized in this report are not easy to compare due to different methodology and data used, as well as different assumptions on the interconnection capacity available. Integration costs of wind power need to be compared to something, like the production costs or market value of wind power, or integration cost of other production forms. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels.

Several issues that impact on the amount of wind power that can be integrated have been identified. Large balancing areas and aggregation benefits of large areas help in reducing the variability and forecast errors of wind power as well as help in pooling more cost effective balancing resources. System operation and working electricity markets at less than day-ahead time scales help reduce forecast errors of wind power. Transmission is the key to aggregation benefits, electricity markets and larger balancing areas.

From the investigated studies it follows that at wind penetrations of up to 20 % of gross demand (energy), system operating cost increases arising from wind variability and uncertainty amounted to about 1–4 €/MWh. This is 10 % or less of the wholesale value of the wind energy.

With current technology, wind power plants can be designed to meet industry expectations such as riding through voltage dips, supplying reactive power to the system, controlling terminal voltage, and participating in system operation with output and ramp rate control. The cost of grid reinforcements due to wind power is very dependent on where the wind power plants are located relative to load and grid infrastructure. The grid reinforcement costs from studies in this report vary from 0 €/kW to 270 €/kW. The costs are not continuous; there can be single very high cost reinforcements. There can also be differences in how the costs are allocated to wind power.

Wind generation will also provide some additional load carrying capability to meet forecasted increases in system demand. This contribution can be up to 40 % of installed capacity if wind power production at times of high load is high, and down to 5 % in higher penetrations and if local wind characteristics correlate negatively with the system load profile. Aggregating larger areas benefits the capacity credit of wind power.

State-of-the-art best practices in wind integration studies include (i) capturing the smoothed out variability of wind power production time series for the geographic diversity assumed and utilising wind forecasting best practice for the uncertainty of wind power production (ii) examining wind variation in combination with load variations, coupled with actual historic utility load and load forecasts (iii) capturing system characteristics and response through operational simulations and modelling (iv) examining actual costs independent of tariff design structure and (v) comparing the costs and benefits of wind power.

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