

Design and Operation of Power Systems with Large Amounts of Wind Power, first results of IEA collaboration

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Abstract: An international forum for exchange of knowledge of power system impacts of wind power has been formed under the IEA Implementing Agreement on Wind Energy. The task “Design and Operation of Power Systems with Large Amounts of Wind Power” will analyse existing case studies from different power systems. There are a multitude of studies made and ongoing related to cost of wind integration. However, the results are not easy to compare. This paper summarises the results from 10 countries and outlines the studies made at European Wind Energy Association and the European system operators UCTE and ETSO. A more in-depth review of the studies is needed to draw conclusions on the range of integration costs for wind power. A state-of-the-art review process of the new IEA collaboration will seek 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 and uncertainty of wind, etc

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 first practical experience from wind integration.

Wind power production introduces more uncertainty in operating a power system: it is variable and partly unpredictable. To enable a proper management of the uncertainty, there will be need for more flexibility in the power system, either in the form of more flexible generation, demand or transmission between areas. How much extra flexibility is needed depends on the one hand on how much wind power there is and on the other hand on how much flexibility there exists in the power system.

In recent years, several reports have been published in many countries investigating the power system impacts of wind power. However, the results on the costs of integration differ and comparisons are difficult to make due to different methodology, 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. Furthermore wind power should not be treated in isolation, but always in relation with the other elements of the power system. 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 wind penetration targets within each country, it is important that commonly accepted standard methodologies are applied related to these issues.

A new R&D Task titled “Design and Operation of Power Systems with Large Amounts of Wind Power Production” has been formed within the “IEA Implementing Agreement on the Co-operation in the Research, Development and Deployment of Wind Turbine Systems” [1]. The work has started in the beginning of 2006 and will continue for three years. The objective is to analyse and further develop the methodology to assess the impact of wind power on power systems. The main emphasis is on the impacts that wind power has on reliability and on efficiency (losses) of the power system. This R&D task will collect and share information on the experience gained and the studies made, with analyses and guidelines on methodologies. The Task will start with producing a state-of-the-art report on the knowledge and results so far and end with developing guidelines on the recommended methodologies when

estimating the system impacts and the costs of wind power integration. Also best practice recommendations may be formulated on system operation practices and planning methodologies for high wind penetration.

2 Power system impacts of wind power

Wind power has impacts on power system reliability and efficiency (Fig 1). These impacts can be either positive or negative.

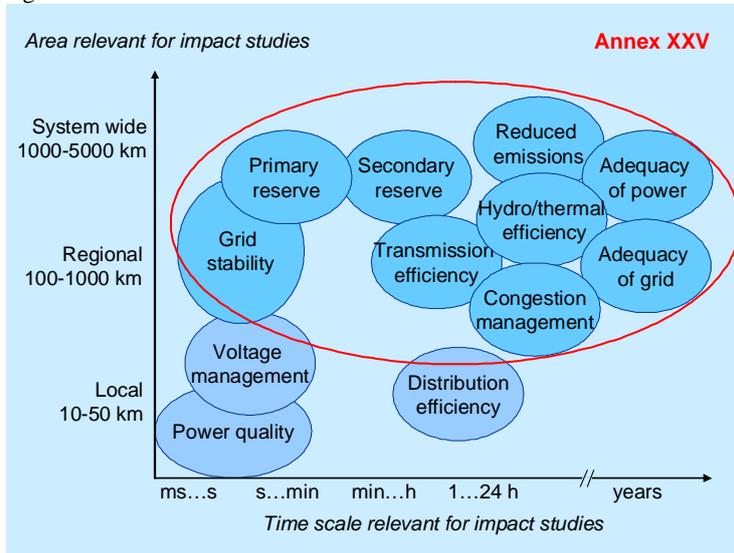


Fig 1. Impacts of wind power on power systems, divided in different time scales and width of area relevant for the studies. In this international collaboration (IEA WIND Task 25), more system related issues are addressed, as opposed to local issues of grid connection like power quality. Primary reserve 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).

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

Regulation and load following: This is about capacity and cost of reserve/regulating power (time-scale minute...half an hour), how the uncertainty introduced by wind power will affect the allocation and use of reserves in the system. Unpredicted part of the variations of large area wind power should be combined with any other unpredicted variations the power system sees, like unpredicted variations in load. 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. The costs will depend on the marginal costs for providing regulation or mitigation methods used in the power system for dealing with increased variability. Market rules will also have an impact, so technical costs can be different from market costs.

Efficiency and unit commitment: This impact is due to production variability and prediction errors of wind power (time scale: hours...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.

Transmission adequacy and efficiency: (time scale hours to years). The impacts of wind power on transmission depend on the location of wind farms 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 farm output control. However, grid reinforcement may be necessary to maintain transmission adequacy. When determining adequacy 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 farms 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 (f.ex. FACTS) at wind plants.

3 Results from existing studies

A wide range of case studies from different power systems have already been made. The national case studies address different impacts: balancing; grid congestions, reinforcement and stability; power adequacy; impact of wind plant technology and control on stability; increased flexibility and value of DSM/storage; forecast model experience; wind and hydro interaction; generation mix and operation methodologies to support a high penetration of wind power. Further case studies will also be made during the 3 years. A short list of on-going research is given in [2].

3.1 Denmark

A stochastic, linear optimisation model specifically aimed at taking wind power forecast errors into account when optimising unit commitment and dispatch of the power plants was developed in the WILMAR project (www.wilmar.risoe.dk). A study with the Wilmar Planning tool done in the EU project Greenet-EU27 [2] 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. 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 model run with stochastic wind power forecasts and the system operation costs in a 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. This is most likely to happen for low amounts of wind power, and did in fact occur in the Base case. Figure 2 shows the results distributed on countries.

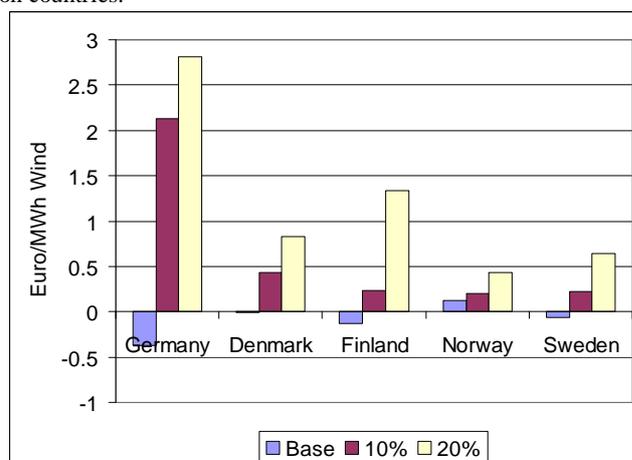


Fig 2. Increase in system operation costs per MWh wind power production for three wind cases (base, 10%, 20%) and divided on countries.

The following conclusions could be drawn from the study:

- The wind power integration costs are lower in hydro dominated countries (especially Norway) compared to thermal production dominated countries (Germany, Denmark). The reason is that hydropower production has very low costs connected to part-load operation and start-up and that hydro-dominated systems are generally not constrained in regulating capacity.
- The wind power integration costs increases when a neighbouring country gets more wind power. Germany and Denmark have the same amount of installed wind power capacity in wind case 10% and 20%, but because the export possibilities become less attractive, due to the increased amounts of wind power capacity in Finland, Norway and Sweden, the integration costs of Germany and Denmark increase from wind case 10% to 20%.
- Germany has the highest integration costs because the wind power capacity in Germany is very unevenly distributed with North-western Germany having a high share of wind power relatively to the electricity demand and the export possibilities out of the region.
- Denmark has the highest share of wind power among the countries, but also excellent transmission possibilities to neighbouring countries compared with e.g. Finland. Therefore the wind power integration costs of Denmark are lower than those of Finland in wind case 20%.

Lund and Münster [3] 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.

The TSO Elkraft [4] (now Energinet.dk) analyses a high wind power scenario in the Nordic power system with 21 GW wind power capacity in 2025 supplemented with a large increase in natural gas power plants. They use Balmorel in their analysis, which is a bottom-up, deterministic, optimization model covering the Nordic countries except Iceland. The study finds that the costs of operating the power system decreases when installing either 500 MW heat pumps or 1000 MW electrical boilers in the CHP systems in Denmark.

Another study made by Energinet.dk [5], [6] investigates the effect of further implementation of wind energy in the western Danish power system on the market; i.e. CHP units and international connections have been disregarded during the study to maintain simplicity and generality. The share of wind power is gradually increased onshore as well as offshore (6 TWh + 20 TWh) from 0% to 100% coverage of the annual energy consumption (26 TWh) using measurement-based time series. The used simulation tool "SIVAEL - simulation of district heating and electricity" solves the week-scheduling problem on an hourly basis and finds the optimum load dispatch minimising variable costs with regard to start-stop, planned overhauls and forced outages. The simulations result - depending on the share of wind power - in different number of conventional units, their different distribution on generation type and different utilisation time per unit taking two generation types into account (coal- and natural gas-fired for base resp. peak load). The results show that the system can absorb about 30% wind power with no surplus electricity. The surplus grows substantially when the share of wind power exceeds a share of about 50%. This surplus has to be served by new products of new market players, for example heat pumps, electric boilers, or other electricity-consuming devices that are not depending on the time of their usage. Pointing on this demand-side a study made by NORDEL [7] identifies demand response as both an alternative and a prerequisite for investments into new production capacity and recommends that all Nordic TSOs prepare action plans for developing demand response. Demand response is defined as short-term change in electricity consumption as a reaction to a market price signal. This enables the customers either to shift the time of consuming, or to shift the energy resource and thereby influence the slope of the demand curve in a diagram with price as a function of quantity. Further interdependencies of technical as well as market aspects have been shown in [8], while a comparison of technical aspects in Denmark, Germany, Spain and Ireland has been made in [9].

3.2 Finland

The most recent study is the PhD "The impact of large scale wind power production on the Nordic electricity system" published in 2004 [10].

In [11] results from simulation with EMPS simulations for Nordic electricity market with 46 TWh/a wind production (12 % penetration of gross demand) are presented. 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. High penetrations of wind power will lower the Nordpool spot market prices by about 2 €/MWh per 10 TWh/a added wind production (10 TWh/a is 3 % of gross demand). This result is assuming that wind power would come as extra production in the market.

Balancing costs: Estimate for the operating reserve requirement due to wind power in the Nordic countries is reported in [12]. The estimate is made from hourly time series for load and wind power, 4 times standard deviation is used as confidence level when looking at the increase in hourly variations from load to net load. The effect of prediction errors day-ahead has not been taken into account; this is only for the real-time hour to hour variations. Existing reserves for disturbances have not been considered; the impact is only estimated on operating reserves used for load following. The increase in reserve requirements corresponds to about 2 % of installed wind power capacity at 10 % penetration and 4 % at 20 % penetration respectively. For Finland this would be twice as much as for the Nordic region, due to lower smoothing of wind power variations in one country compared to larger area and the relatively small load variations in Finland. If new natural gas capacity was built for this purpose, and the investment costs was allocated to wind power production this would increase the cost of wind power by 0.7 €/MWh at 10 % penetration. The increase in use of reserves would be about 0.33 TWh/a. The cost of this increased use of reserves, at a price 5-15 €/MWh would be 0.1-0.2 €/MWh. In total this would mean about 1 €/MWh for 10 % (energy) penetration. For 20 % penetration a similar calculation would give 2 €/MWh for the Nordic system. Calculating for Finland only gives about 2 €/MWh for 10 % (energy) penetration and 3 €/MWh for 20 % penetration.

3.3 Germany

The main existing study covering wind integration in Germany is German Energy Agency's (dena) study "Planning of the integration of wind energy into the German grids ashore and offshore regarding the economy of energy supply", 2005 [13]. The study ascertained that based on the assessed regional distribution and identified grid reinforcement and extension, the integration of a total of 36 GW of wind power capacity into the German transmission system will be possible. This is in line with the target of a 20 % share of renewable energy in the German electricity supply by 2020 from Federal Government.

The installed wind power scenario of the dena-study forecasts an increase from 14,600 MW in 2003 to approximately 36,000 MW in 2015. This corresponds to approximately 25 % of conventional capacity (14 % of projected gross demand). On the basis of the age structure of today's power plant system and the agreed phase-out of nuclear energy, an estimated 40,000 MW of new installed power plant capacities must be in place by 2020. This power plant renewal process falls in the same period as the planned expansion of wind energy use. This gives rise to both the possibility and the task of adapting the structure of the power plant system to meet the changing conditions that are characterised by an increasing and greatly fluctuating infeed from wind energy that is to be included as a priority.

Grid reinforcement need: in windy periods, network bottlenecks can be expected already for the 2007 time horizon unless new lines are constructed. 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 in order to transport wind power to the load centres. 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). In view of the high speed of expansion in wind energy use, the requirement for transmission routes as determined in the study has resulted in ambitious targets being set for completing the complex and lengthy approvals procedure on time.

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).

Balancing requirements: 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:

- an 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.

- an 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.

Impact on system stability: 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 farms in the high voltage grid will be necessary, for instance in view of fault-ride-through and grid voltage maintenance respective 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 extended more specific control and protection rules. The implementation of the new and extended measures will e.g. improve and stabilize wind turbines behaviour and results in decreasing loss of wind power following disturbances [14].

3.4 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. A summary of the most recent studies to date and their key findings are as follows:

In the TSO ESBNG report from 2004 [15] 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. The system assessment methodology was generating system simulation using a unit commitment and dispatch simulator. 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 CO₂ abatement in the Irish electricity system is €120/Tonne.

In SEI ILEX/UMIST/UCD/QUB report from 2004 “Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System” [16] the wind input assessment methodology was to use a time series generated from statistical manipulation of historic wind farm data. The system assessment methodology was generating system simulation using a proprietary system dynamic model. The study findings were that fuel cost and CO₂ savings up to a 1500MW wind power penetration in the ROI system were directly proportional to the wind energy penetration. 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.

In ESBI report for SEI “Renewable Energy Resources for Ireland 2010 & 2020” the wind input assessment methodology in this study was to use the economically viable resource based upon the 2003 wind atlas. The system assessment methodology used results from ESBNG 2004 study detailed above to find limits on wind energy penetration of 1000MW in 2010 and 1250MW in 2020. The report also found that if replacement plant for conventional plant retired in 2016 were aeroderivative OCGT rather than CCGT the 2020 limit became 3500MW.

In SEI Brattle Group report “Renewable Energy in the New Irish Electricity Market” the wind input assessment methodology was a time series from the SEI study on regulating reserves. The system assessment methodology used generating system dispatch simulation (Henwood) to examine the effects upon conventional plant. The study found that the costs of ramping & start-ups were reasonable for a 1500MW wind energy penetration.

3.5 Netherlands

Grid reinforcement need and costs: 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 study started with determining the best locations for 6000 MW wind power and investigating the options to transport the power to the on-shore substation [17, 18, 19]. This part of the study concluded that for the relatively short distances between wind farms and substation, AC connections are to be preferred. 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. This showed that additional voltage control equipment is required and that a limited number of lines have to be upgraded. Investment costs to grid were estimated to 344-660 ME, depending on location/scenario (about 4% of est. total investment for 6 GW wind). In 2005 the Connect 6000 study was continued by investigating the phased introduction of offshore wind power according to the ECN-CPB scenarios of September 2005. Different options of connecting the wind farms have been compared from an economic as well as a spatial and planning point of view [20]. The study was completed by investigating the legal and political aspects of large scale offshore wind power.

3.6 Norway

Options for large scale integration of wind power in Norway are summarised in recent report [21]. Wind power may in the future constitute a significant part of the Norwegian electricity supply. 20 TWh annual wind generation is a realistic goal for 2020 assuming wind farms on-land and offshore. Local control enables operation of a large wind farm on a fairly weak regional grid, and marked based balancing tackles large magnitudes of wind power. Wind generation impact on power system operation and adequacy will be overall positive. Combining wind and hydro provides for a more stable annual energy supply than hydro alone, and wind generation will generally be higher in the winter period than in the summer. The hourly wind power variations may be significant within local areas, but uncorrelated between distant sites. Hence, sufficient transmission capacity may be a key for efficient operation of a future Norwegian power system with a large share of wind power.

Studies on wind/hydro integration have focused on planning and operation of large wind farms in areas with limited power transfer capacity, [22, 23]. The studies involve assessment of system operation, wind and hydro variations and hour-by-hour simulations. By accepting temporary grid congestions large amounts of wind power can be integrated without costly grid reinforcements, but utilizing the control possibilities of modern wind farms. For grid congestion that appears a few hours per year only, the cost of lost generation will be modest and may be economic over the alternatives of limiting wind farm capacities or increasing the grid transfer capacity.

The impact of wind power on system adequacy for one region in Norway was reported in [24]. 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. 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.

3.7 Portugal

In Portugal, one of the most ambitious wind energy plans in Europe is under development aiming to achieve an energy penetration up to 15% percent in 2013 [25]. Two studies related to wind integration have been completed under the 2001/ 77 - EC Directive wind capacity goals: Power system stability study of the Iberian network [26] and Assessment of the extra power reserves requirements ([27], [28]). The Iberian peninsula is an area of Europe with a peak load of above 50000 MW but which is very weakly connected to the rest of the UCTE grid. The fact that the France-Spain interconnection capacity level is so small (less than 1800 MW now; max 4000 MW future) is a considerable handicap when both Iberian countries decide to set ambitious goals of wind power. A study carried out in 2004 by the Portuguese TSO (REN) showed a danger of instability in Portugal + Spain following a short circuit in certain locations of the transmission network. At this moment, REN and its Spanish counterpart REE are completing a second and more detailed joint study with higher wind targets (5100 MW in Portugal and 20000 MW in Spain) that shows also that possibility. The new grid codes with fault ride through were proved to be required, at least at certain parts of the grid. The possibility to use Facts is also under study [29].

Grid reinforcement need and costs: In the overall period 2005 – 2010, the investment directly attributable to renewables, mostly for wind parks, will total 200 Million €. These numbers do not consider the investment of the wind park main substation nor the direct line to the TN connection point, which are built by the promoter.

Currently there is no available information on balancing costs.

3.8 Sweden

A study of 4000 MW wind power in Sweden was published in 2005 [30]. The Swedish additional reserve requirements for different time horizons, based on probability and forecast approach, are tabulated below.

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)

It has been concluded that decisive parameters for the additional requirements are the wind power penetration level and the consumption variations. In power systems with large consumption variations, like the Swedish, lower additional reserves are required compared with power systems with lower consumption variations, like the Finnish. The study indicates that the requirement of additional regulating/reserve capacity is comparatively small, at least for the time horizon 1 hour and with an approach including probability and forecasts. In many cases these extra requirements may also already be available which means that no extra investments are needed.

Results on coordination of wind power and hydropower in an area with limited export capacity [31]: Different strategies for how to coordinate wind power and hydropower in a deregulated framework has been studied. 30-90 MW of wind power has been balanced with 250 MW of hydropower with an available transmission of 250 MW. The result is that coordination of wind power and hydropower can be mutually beneficial for the wind power utility and hydropower utility. The coordination greatly decreases wind energy curtailments and also leads to more efficient utilization of the existing transmission lines, without negative economical impact on hydro power producer.

In earlier work, the impact on hydro power efficiency was estimated [32]. The decrease of efficiency in the hydro power system of Sweden due to the forecast errors of wind power production would be equivalent to 1 % of the wind power production at a wind power penetration of 4 % of the yearly gross demand (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 with 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).

3.9 UK

Investigations of the effects of wind power of the electricity system operation and development date from early 1980s. The assessments were primarily focused on the impact of wind on generation and transmission systems. Several studies quantifying the integration costs of wind power have been published in UK [33,34,35,36] and a summary of the key findings of these studies is presented below.

Balancing costs: The balancing costs arise as reserve plant is part-loaded and, in consequence operates at lower efficiency. Extra plant may be needed if the existing capacity is insufficient, but the amounts involved are very modest – around 5% of the wind plant capacity, at the 20% penetration level (% of gross demand). Estimates of extra reserve costs from [37] used market costs, which may be expected implicitly to include a capital recovery element. Estimates in [33] tie in with both of these (with a spread of plus or minus 10%). A value of £2.38 per MWh of wind produced for 10% wind is used, rising to £2.65/MWh at 15% and £2.85/MWh at 20%.

Grid reinforcement needs and costs: The location of wind generation, like conventional generation, can have a significant effect on transmission. Historically, transmission costs 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.

In [37] costs of between £275m and £615m to accommodate 8 GW of wind, i.e. between £35/kW and £77/kW. In [33] the effects of connecting wind farms at various locations across the country on the transmission reinforcement cost was considered. 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. 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. The effect of these wider ranges is illustrated in the sensitivities shown below. In [34] a value £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 [33], 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 farms 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 combination 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.

Capacity credit: 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 than nine winters in one hundred, i.e. a 9% risk), the amount of conventional generation that can be displaced by wind generation was evaluated using the annual half-hourly profiles of wind outputs, developed from historic wind generation data. [33] used a one-year time series of actual wind generation data. While this dataset provided statistically significant observations of the general variability of wind and correlation with demand, it is too short to permit wind variations during high demand conditions to be extensively sampled. However, analysis of a 5 year time series of wind speeds used by National Grid in an assessment of balancing requirements, and an earlier study by the CEGB, do not provide any statistical evidence for wind variations at peak being substantially different to those at other demand levels for similar times of the year. A more detailed analysis of the issues, with results from various British and overseas studies, came to a similar conclusion. On this basis, for the purposes of assessing capacity credit, the typical distribution of wind output seen in the various time series available will also occur during high demand conditions. 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 26 GW, about 5GW of conventional capacity could be displaced, giving a capacity credit of about 20%.

Impact on system stability [38]: Much speculation exists concerning the influence of wind farms on system operation and stability. Wind farms based on Fixed Speed Induction Generators (FSIGs) have poor transient stability characteristics but this report shows that 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 to 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.

Value of fault ride through capability for wind farms: the 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 (www.sedg.ac.uk) 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 CO₂ 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 farms would be economically efficient.

3.10 USA

An increasing number of traditional utilities and system operators are performing operational impact studies.

The Minnesota Dept. of Commerce/Enernex Study was completed in 2005 [39]. It estimated the impact of wind in a 2010 scenario of 1500 MW of wind in a 10 GW peak load system. 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. A monopoly market structure, with no operating practice modification or change in conventional generation expansion plan, was assumed. Incremental regulation due to wind was found to be 8 MW (at 3 σ confidence level). Incremental intra-hour load following burden increased 1-2 MW/min. (negligible cost). Hourly to daily wind variation and forecasting error impacts are the largest cost items. 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. A capacity credit of 26%-34% was found with a range of assumptions using the ELCC method.

The NYSERDA/GE Energy Study for the New York ISO was completed in 2005. [40]. It 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.

The Xcel Colorado/Enernex Study (2006) [41] examined 10% and 15% penetration cases (wind nameplate to peak load) in detail for ~7 GW peak load system. 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.

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. A wind capacity credit of 23%-25% of a benchmark gas unit was found.

3.11 EWEA

The EWEA Grid Report [42] has made an analysis of wind power integration issues at the European level. Based on information from studies and operational experience, the report concludes that it is perfectly feasible to integrate the targeted wind power capacity of 300 GW in 2030 – corresponding to an average penetration level of up to 20%. The costs will be in the same order of magnitude as the individual contributions from conventional generation. The constraints of increasing wind power are not technical per se but are a matter of regulatory, institutional and market modifications and should be dealt with in the broader European power market context. Issues that need to be addressed are related to changed approaches in operation of the power system, connection requirements for wind power to maintain a stable and secure supply, extension and modification of the grid infrastructure, influence of wind power on the system adequacy and security of supply. Finally institutional and legal barriers to increased wind power penetration need to be addressed and overcome.

3.12 UCTE and ETSO

Currently, more than 70 % of the wind power installed worldwide is integrated in the UCTE synchronous interconnected network of continental Europe (UCTE: The Union for the Co-ordination of Transmission of Electricity).

In 2004 UCTE analyzed the level of integration of wind power in the UCTE interconnected network, the state of the art on wind power converters and, after a review of the more frequent problems associated to this type of energy, suggests some recommendations for system planning and operating planning and the requirements for connection of wind farms [43]. Additionally UCTE published a position paper which examined the profile of wind power, its impact on the network, security of supply and the quality of the energy delivered. It further deals with the reasons to establish certain technical requirements for the connection of wind power generation to the network [44]. In 2005 UCTE proposed a number of actions and investigations that need to be taken by legislators, regulators, grid operators and grid users aiming at establishing a harmonised set of rules for the successful integration of wind power into European electricity systems [45]:

- a harmonized approach for studies of new technology for accommodation of new RES generation
- a European promotion scheme for RES taking account of the conditions of the transmission infrastructure
- compatible market arrangements required for permanently safe and stable power supply in Europe
- harmonization and synchronization of grid planning and RES expansion
- national rules and procedures expediting the process of granting licences and authorisation for new urgently needed high-voltage transmission lines and grid reinforcements

The Association of European Transmission System Operators (ETSO) published in 2004 a report on Renewable Energy Sources (RES) [46] which deals with Guarantee of Origin (GoO) for renewables; Market integration of renewables in the electricity market and Technical integration of renewables in the electricity system. In 2005 ETSO presented the report “Integration of Renewable Energy Sources in the Electricity System - Grid Issues“[45]. The report lists a number of challenges and recommended actions connected with the integration of RES in the electricity systems: grid extension, system stability, balance management and system adequacy and impact on cross-boarder electricity transits.

In 2006 ETSO and UCTE presented views on the Integration of Wind Energy in the European Electricity System and announced a new wind integration study by European TSOs starting in 2006 [47]. 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.

4 First results from reviewing the studies made so far

A summary for the quantified results for balancing requirements presented in section 3 is presented in Fig 3 and 4.

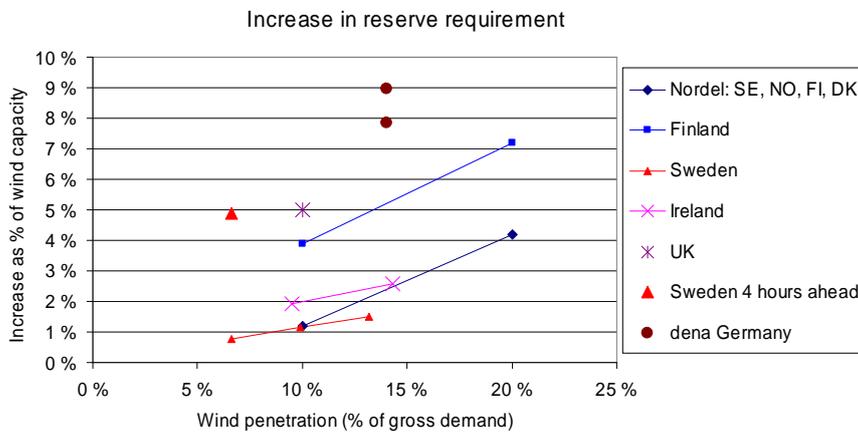


Fig 3. Results for the increase in reserve requirement due to wind power. German dena estimates are taking into account the day-ahead uncertainty (for up and down reserves separately). For the others the effect of variations during the operating hour is considered (for UK and Sweden also the 4 hour-ahead uncertainty has been evaluated).

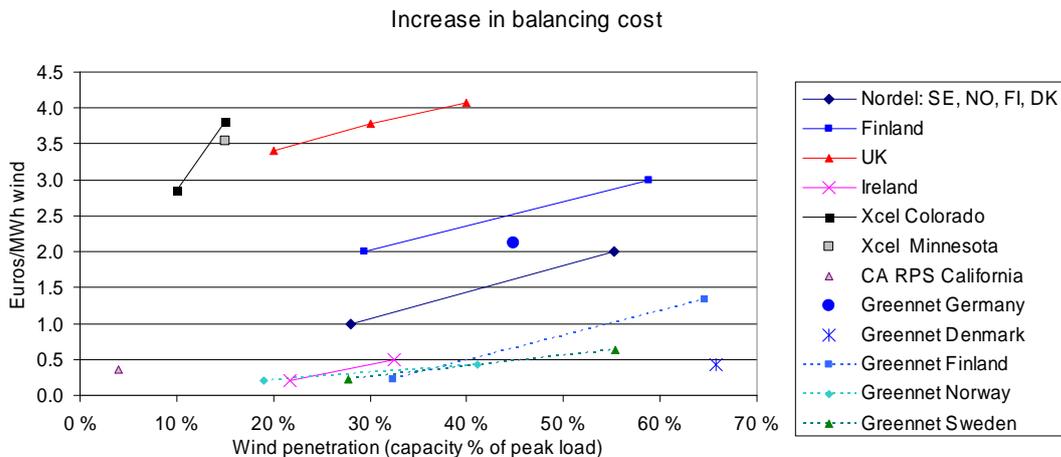


Fig 4. Results from estimates for the increase in balancing and operating costs due to wind power. The currency conversion used here is 1 € = 0.7 £ and 1 € = 1.3 US\$.

It can be seen that there is considerable scatter in results for different countries and regions. In Fig 3 some of the differences are due to the different time scales used for estimating – for the German dena study the average reserve requirement is from day-ahead, whereas for the Nordic countries and Ireland only the increased variability during the operating hour has been estimated. For UK, the increased variability to 4 hours ahead has been taken into account. The difference in time scales is one reason why the results in Fig 4 are not directly comparable. For the Greennet-EU27 study only operating costs have been estimated whereas also investments for new reserves are included in some results. Some studies incorporate the possibilities for reducing operation costs through power exchange to neighbouring countries, whereas other studies analyse the country in question without taking transmission possibilities into account. For estimating the increase in operating costs of a power system due to wind power the methodology can be very different: the results can be based on MW values converted to monetary values assuming thermal power plant investment and operating costs or assumptions on how a thermal alternative to wind would operate can be in the background assumptions.

For the grid reinforcement, the reported results from UK are £50-100 / kW (70-140 €/kW). The 6000 MW offshore in the Netherlands is estimated to cause 60-110 €/kW costs whereas the Portugal figure amounts to 53 €/kW. The German dena study results are about 100 €/kW. The grid reinforcement costs are not continuous, there can be single very high cost reinforcements, like in Germany the largest investments of 0.6 and 1 billion €

Challenges for the case studies 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 following approach has resulted as a state-of-the-art best practice so far:

- Capture the smoothed out variability of wind power production time series for the geographic diversity assumed. Use actual data from several wind farms and met towers, or synchronized weather simulation. Utilize wind forecasting best practice for 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 operational simulations and modeling
- Examine actual costs independent of tariff design structure

For high penetration levels of wind power, also 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 the objective in mind. For high penetrations also the surplus wind power needs to be dealt with, f.ex. by transmission to neighbouring areas, storage (e.g. thermal) or demand side management. 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.

Further work on review and analyses of the existing work will be conducted within the IEA collaboration. A state-of-the-art report will be made during 2006, summarising results and reviewing methodologies, tools and data used in studies made so far on power system impacts of wind power. Explaining factors for different results will be sought:

- Wind penetration levels (with and without interconnection possibilities);
- How large is the system area? Wind resource geographic diversity, load aggregation benefits
- Conventional generation mix, power system operational characteristics of the installed generation plants, inherent variability of system load, the network topology as well as the rules and strategies practised in relation to transmission capacity and treatment of imbalances; market-based or self-provided ancillary services
- What has been taken into account? How conservative are estimates?

Also the representation of the results of the studies is important when making comparisons: both the terms and the metrics used in the power systems and in representing the results vary:

- How wind power penetration is defined: relative to installed generation capacity, consumed energy
- Reserves: time scales for primary /secondary reserves, division to disturbance /operational reserves, time scales for determining imbalances taken care of by the reserves, i.e. operational hour or forecast errors in the day-ahead or intraday period
- Integration cost, avoided cost, compared to what: integration cost of other production forms, variable costs or fixed plus variable costs, with or without transmission? Market versus technical cost, social cost?

5 Experience from existing power systems with wind power

Experience from regions where wind power produces up to 35 % of yearly gross demand was gathered from West Denmark, Schleswig-Holstein in Germany and Gotland in Sweden [48]. The regions are part of larger power systems; however, some impacts due to large wind power production can be seen. From the experience reported, it seems that when making sure that the following aspects are covered, the wind power can be managed either within the region or using interconnectors and outside region solutions:

- the interconnectors can react fast enough
- most of the wind farms do not trip off due to grid faults and thus cause a dimensioning fault
- it is possible to curtail the wind power production in critical (rare) occasions

6 Conclusions

An international forum for exchange of knowledge of power system impacts of wind power has been formed under the IEA Implementing Agreement on Wind Energy. The task “Design and Operation of Power Systems with Large Amounts of Wind Power” will analyse existing case studies from different power systems.

There are a multitude of studies made and ongoing related to cost of wind integration. However, the results are not easy to compare. This paper summarises the results from 10 countries and outlines the studies made at European Wind Energy Association and the European system operators UCTE and ETSO.

A more in-depth review of the studies is needed to draw conclusions on the range of integration costs for wind power. A state-of-the art review process of the new IEA collaboration will seek 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 and uncertainty of wind, etc.

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