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

Book *in* VTT Tiedotteita - Valtion Teknillinen Tutkimuskeskus · January 2009

iea wind

TECHNOLOGY • RESEARCH • HIGHLIGHTS • VISIONS • SCIENCE •

75

IEA Wind Task 25

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

Hannele Holttinen | Juha Kiviluoma | André Robitaille | Nicolaos A. Cutululis | Antje Orths | Frans van Hulle | Ivan Pineda | Bernhard Lange | Mark O'Malley | Jody Dillon | E.M. Carlini | C. Vergine | Junji Kondoh | Madeleine Gibescu | John Olav Tande | Ana Estanqueiro | Emilio Gomez | Lennart Söder | J. Charles Smith | Michael Milligan | Debbie Lew

VTT

VTT TECHNOLOGY 75

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

Final summary report, IEA WIND Task 25, Phase two 2009–2011

Hannele Holttinen, Juha Kiviluoma, VTT, Finland
André Robitaille, Hydro Quebec, Canada
Nicolaos A. Cutululis, DTU Wind Energy
Antje Orths, Energinet.dk, Denmark
Frans van Hulle, Ivan Pineda, EWEA
Bernhard Lange, Fraunhofer IWES, Germany
Mark O'Malley, Jody Dillon, UCD, Ireland
E.M. Carlini, C. Vergine, Terna, Italy
Junji Kondoh, AIST; Yoh Yasuda, Kansai University, Japan
Madeleine Gibescu, TU Delft, Netherlands
John Olav Tande, SINTEF, Norway
Ana Estanqueiro, LNEG, Portugal
Emilio Gomez, University Castilla La Mancha, Spain
Lennart Söder, KTH, Sweden
J. Charles Smith, UWIG, USA
Michael Milligan, Debbie Lew, NREL, USA

ISBN 978-951-38-7910-5 (URL: http://www.vtt.fi/publications/index.jsp)

VTT Technology 75

ISSN-L 2242-1211
ISSN 2242-122X (Online)

JULKAISIJA – UTGIVARE – PUBLISHER

VTT
PL 1000 (Tekniikantie 4 A, Espoo)
02044 VTT
Puh. 020 722 111, faksi 020 722 7001

VTT
PB 1000 (Teknikvägen 4 A, Esbo)
FI-02044 VTT
Tfn +358 20 722 111, telefax +358 20 722 7001

VTT Technical Research Centre of Finland
P.O. Box 1000 (Tekniikantie 4 A, Espoo)
FI-02044 VTT, Finland
Tel. +358 20 722 111, fax + 358 20 722 7001

Design and operation of power systems with large amounts of wind power
Final summary report, IEA WIND Task 25, Phase two 2009–2011

Hannele Holttinen, Juha Kiviluoma, André Robitaille, Nicolaos A. Cutululis, Antje Orths, Frans van Hulle, Ivan Pineda, Bernhard Lange, Mark O'Malley, Jody Dillon, E.M. Carlini, C. Vergine, Junji Kondoh, Madeleine Gibescu, John Olav Tande, Ana Estanqueiro, Emilio Gomez, Lennart Söder, J. Charles Smith, Michael Milligan & Debbie Lew.
Espoo 2013. VTT Technology 75. 81 p. + app. 13 p.

Abstract

This report provides a summary of the results from recent wind integration studies. The studies address concerns about the impact of wind power's variability and uncertainty on power system reliability and costs as well as grid reinforcement needs. Quantifiable results are presented as summary graphs: results as a MW-increase in reserve requirements, or €/MWh increase in balancing costs, or results for capacity value of wind power. Other results are briefly summarised, together with existing experience on the issues.

There is already significant experience in integrating wind power in power systems. The mitigation of wind power impacts include more flexible operational methods, incentivising flexibility in other generating plants, increasing interconnection to neighbouring regions, and application of demand-side flexibility. Electricity storage is still not as cost effective in larger power systems as other means of flexibility, but is already seeing initial applications in places with limited transmission. Electricity markets, with cross-border trade of intra-day and balancing resources and emerging ancillary services markets, are seen as promising for future large penetration levels for wind power.

Keywords wind power, wind energy, wind integration, grid integration, reserve requirements, capacity credit, transmission planning

Preface

A Research and Development (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. The aim of the R&D task is to 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 following countries and institutes have been involved in the collaboration:

- Canada: Transmission System Operator (TSO) Hydro Quebec (IREQ)
- Denmark: DTU Wind Energy (Risø-DTU); TSO Energinet.dk
- European Wind Energy Association (EWEA)
- Finland: Technical Research Centre of Finland (Operating Agent) (VTT)
- Germany: Fraunhofer IWES; TSO Amprion
- Ireland: SEI; UCD; ECAR; TSO Eirgrid
- Italy: TSO Terna
- Norway: SINTEF/NTNU; TSO Statnett
- Netherlands: ECN; TUDelft
- Portugal: LNEG; TSO REN; INESC-Porto, IST
- Spain: University Castilla La Mancha; TSO Red Eléctrica de España (REE)
- Sweden: KTH
- UK: Centre for Distributed Generation & Sustainable Electrical Energy
- USA: National Renewable Energy Laboratory (NREL); UVIG; U.S. Department of Energy (DOE).

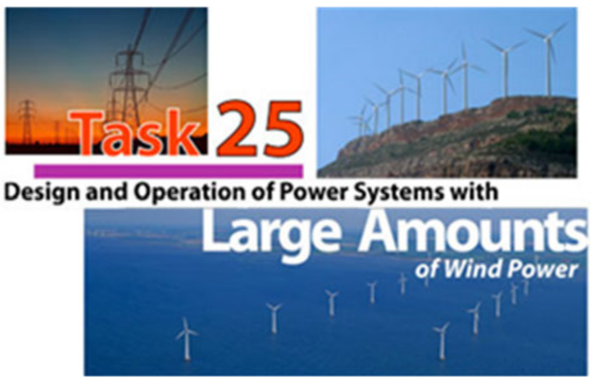
IEA Wind Task 25 started with producing a state-of-the-art report on the knowledge and results that have been gathered so far, which were published in the VTT Working Papers series in 2007 and further expanded to final report in 2009 (VTT Research Notes 2493). In these reports, a summary of selected, recently finished studies was presented. The Task 25 is also working on developing guidelines on the recommended methodologies when estimating the system impacts and the costs of wind power integration. The results of the second 3-year period are summarised in this report. The work will continue with a third 3-year period (2012–2014).

Credits and Acknowledgements:

Acknowledgements from SINTEF: Steve Völler and Hossein Farahmand

Acknowledgements from TU Delft: Ana Ciupuliga and Barry Rawn

Acknowledgements from Universidad de Castilla-La Mancha (UCLM): Spanish Wind Energy Association (Alberto Ceña and Kilian Rosique)



Contents

Appendices

List of Acronyms

AC	Alternating Current
AIGS	All Island Grid Study
BA	Balancing Area
CHP	Combined Heat and Power
DC	Direct Current
ELCC	Effective Load Carrying Capability
ENTSO-E	European Network of Transmission System Operators for Electricity
EU	European Union
EWITS	Eastern Wind Integration and Transmission Study
FLM	Flexible Line Management
FRT	Fault-Ride-Through
HVDC	High-Voltage Direct Current
IEA	International Energy Agency
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
LOLP	Loss-of-load probability
MAE	Mean Absolute Error
NERC	North American Electric Reliability Corporation
PHS	Pumped Hydro Stations
REE	Red Eléctrica de España
RES	Renewable energy sources
SNSP	System Non-Synchronous Penetration
TSO	Transmission System Operator
TYNDP	Ten-Year-Network-Development-Plan
VSC-HVDC	Voltage source controlled high voltage direct current
WWSIS	Western Wind and Solar Integration Study

Executive Summary

This report summarises recent findings on wind integration from studies made and real experience in integration from the 15 countries participating in the International Energy Agency (IEA) Wind collaboration. Most of the results and methodologies discussed are also valid for other variable renewables besides wind power. Many wind integration studies already incorporate solar energy.

The national case studies address impacts that are grouped under balancing the power system on different short-term time scales: grid congestion, reinforcement, and stability as well as power adequacy (i.e., capacity value of wind). Appendix 1 provides a summary of on-going research in the national projects contributing to Task 25.

Wind power production introduces additional variability and uncertainty into the operation of the power system. Without wind power, the system has to balance the varying load with its forecast uncertainty. To meet the challenge of balancing more variability and uncertainty, there is need for more flexibility in the power system. The need for additional flexibility required depends on how much wind power is embedded in the system and the level of existing flexibility in the power system.

The characteristics of variability and uncertainty in wind power are presented from experience of measured data from large-scale wind power production and forecasting. This data is important as input to integration studies. There is a significant geographic smoothing effect in both variability and uncertainty of wind power when looking at power system wide areas. Failure to capture this smoothing effect will affect the estimates for wind impacts on power systems. The smoothing effect of variability can be seen in the measured extreme variations for different size areas. Variability is also lower for shorter time scales. The smoothing effect can also be seen from the general shape of duration curves for wind power production levels and step changes – there is more time during the year with an average level of production and close to zero variability when looking at larger areas. The mean absolute error for large-scale wind power production forecast errors is currently in the range of 4–8% of installed wind capacity when forecasting day-ahead (12–36 hours ahead.). The uncertainty of wind power production will be reduced as more accurate forecasting methods are developed. Large shares of offshore wind power, on the other hand, will increase the forecast errors.

The operating reserve requirement addresses short-term flexibility for power plants that can respond to load and generation unbalances. These are caused mainly by unpredicted variations. Also, any variability inside the time step for the dispatch interval, often in the range of 5–60 minutes, is managed with operating reserves. The reserves are operated according to total system net imbalances, for generation and demand, not for each individual source of imbalance. The computation of reserve requirements necessitates data for uncertainty and variability for demand, wind generation, and other generation as inputs. For wind power, the forecast horizon time scale is a crucial assumption because the uncertainty will reduce more significantly than demand at shorter time scales. There is a large range of results for estimates of increases in reserve requirements. This is mainly due to different time scales of uncertainty taken into account in different studies:

- If only hourly variability of wind is taken into account when estimating the increase in short-term reserve requirement, the results are 3% of installed wind capacity or less, with penetrations below 20% of gross demand.
- When 4-hour forecast errors of wind power are taken into account, an increase in short-term reserve requirement of up to 9–10% of installed wind capacity has been reported for penetration levels of 7–20% of gross demand.

Increasing reserve requirement is usually calculated for the worst case. However, this does not necessarily mean new investments for reserve capacity – rather, generators that were formerly used to provide energy could now be used to provide reserves. The experience so far is that wind power has not caused investments for new reserve capacity. However, some new pumped hydro schemes are planned in the Iberian peninsula to manage more than 20% wind penetration levels in the future.

Because wind power output varies, it is now widely recognized that wind-induced reserves should be calculated dynamically: if allocation is estimated once per day for the next day instead of using the same reserve requirement for all days, the low-wind days will make less requirements on the system. Avoiding allocation of unnecessary reserve is cost effective and can be needed in higher penetration levels of wind power. The time steps chosen for dispatch and market operation can also influence the quantity and type of reserve required for balancing. For example, markets that operate at 5-minute time steps, can automatically extract balancing capability from the generators that will ramp to fulfil their schedule for the next 5-minute period.

The variability and uncertainty of wind power will impact how the balance of the conventional power plant in a system is run. Changing the output level from the plants will incur costs due to additional ramping and starts/stops. To study the impact of wind on operation of power systems, simulation model runs that optimise the dispatch of all power plants to meet varying load are made. Most results on balancing costs are based on comparing costs of system operation without wind and adding different amounts of wind. It is challenging to extract system balancing costs from the total operational costs, including fuel costs. Any alternative to wind would also influence fuel costs. At wind penetrations of up to 20% of gross demand (energy), system operating cost increases, arising from wind variability and uncertainty amounting to approximately 1–4.5 €/MWh. This is 10% or less of the wholesale value of the wind energy. In addition to estimates, there is some experience with actual balancing costs for the existing wind power from electricity markets: 1.3–1.5 €/MWh for 16% wind penetration (Spain), and 1.4–2.6 €/MWh for 24% wind penetration (West Denmark). When estimating balancing costs, a general conclusion is that if interconnection capacity is allowed to be used for balancing purposes, then the balancing costs are lower compared to the case where they are not allowed to be used. Other important factors that were identified as reducing integration costs were: aggregating wind plant output over large geographical regions, and scheduling the power system operation closer to the delivery hour.

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 centres. The issue is generally the same, be it modern wind power plants or any other power plants. The grid reinforcement needed for wind power is therefore very dependent on where the wind power plants are located relative to load and grid infrastructure, and one must expect results to vary from country to country. Grid studies involve a more detailed simulation of power flows in the transmission grid, to confirm the steady-state adequacy and utilization of the transmission system and to assess if the grid is sufficiently strong to cope with added wind power plants also during significant failures. Dynamic system stability analyses are usually not performed at lower penetration levels unless particular stability issues are foreseen in the system. Wind turbine capabilities are still evolving and may mitigate some potential impacts of wind power. There is a trend towards regional planning efforts around the world. The large offshore plans in Europe have launched new research on offshore grids.

The allocation of grid investments to wind power is challenging, in a similar manner to balancing costs. System operators rarely make allocation of grid infrastructure because new infrastructure usually benefits all users. The investments are made for improving electricity market operation, to increase the security of the system and to bring about strategic transitions in the long-term sustainability of electricity supply. Even in cases where wind power would be the main reason for investing, after the grid is built, it is not possible to allocate the benefits to any single user.

Wind power's contribution to the system's power adequacy is its capacity value. Wind power has a capacity value in addition to its energy value. The recommended methodology for assessing the capacity value of wind power is Effective Load Carrying Capability (ELCC) based on loss of load expectancy calculations. The capacity value of wind will decrease as wind penetration increases. The results summarised in this report show a range from 40% of installed wind power capacity (in situations with low wind penetration and a high-capacity factor at times of peak load) to 5% in higher wind penetrations, or if regional wind power output profiles correlate negatively with the system load profile (i.e., low capacity factor at times of peak load). Aggregation benefits apply to capacity credit calculations – for larger geographical areas, the capacity credit will be higher.

There is already significant experience in integrating wind power in power systems. The mitigation of wind power impacts include more flexible operational methods, incentivising flexibility in other generating plants, increasing interconnection to neighbouring regions, and application of demand-side flexibility. Electricity storage is still not as cost effective in larger power systems as other means of flexibility, but is already seeing initial applications in places with limited transmission. Electricity markets, with cross-border trade of intra-day; balancing resources; and emerging ancillary services markets are seen as a positive development for future large penetration levels of wind power.

Estimating the integration costs of wind power is challenging because capturing and allocating costs are not straightforward. The system services of transmission grid and real-time balancing are there for all users. While it is very difficult to calculate the costs of integrating wind, estimates indicate that these costs are manageable. When considering the question of integration costs, it is also important to keep in mind that all generation sources, including nuclear and fossil plants, have costs associated with integrating them in the grid and managing their individual characteristic operational capabilities to provide a stable and reliable electricity supply to meet varying load.

1. Introduction

The existing targets for wind power anticipate a high penetration of wind power in many countries. It is technically possible to integrate very large amounts of wind capacity in power systems, with the limits arising from how much can be integrated at socially and economically acceptable costs. There is already first practical experience from wind integration (Figure 1) from Denmark, Portugal, Spain, and Ireland with more than 15% penetration levels on an annual basis (in electrical energy). Also, in several regions – including Northern Germany, the Midwest United States, Central-Southern Italy, Sicily, and Sardinia – penetration levels of more than 20% give insights of how to cope with higher penetration levels.

Wind power production introduces additional variability and uncertainty into the operation of the power system, over and above that which is contributed by load and other generation technologies. To meet this challenge, there is a need for more flexibility in the power system. The increased need for flexibility required depends on how much wind power is embedded in the system as well as how much flexibility already exists in the power system.

Because 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. In recent years, numerous reports have been published in many countries investigating the power system impacts of wind generation. 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 also be conservative due to lack of sufficient data. Some efforts on compiling the results have been made in DeMeo et al., (2005); Smith et al. (2007); UKERC, (2006); Ackermann & Kuwahata (2011); and by IPCC in O'Malley et al. (2011). However, the conclusion has been that due to a lack of detailed information on the methodologies used, a direct comparison can only be made with few results. An effort for more in-depth review of the studies was made under this international collaboration in the state-of-the-art report (Holttinen et al., 2007) and final report 2006–2008 (Holttinen et al., 2009).

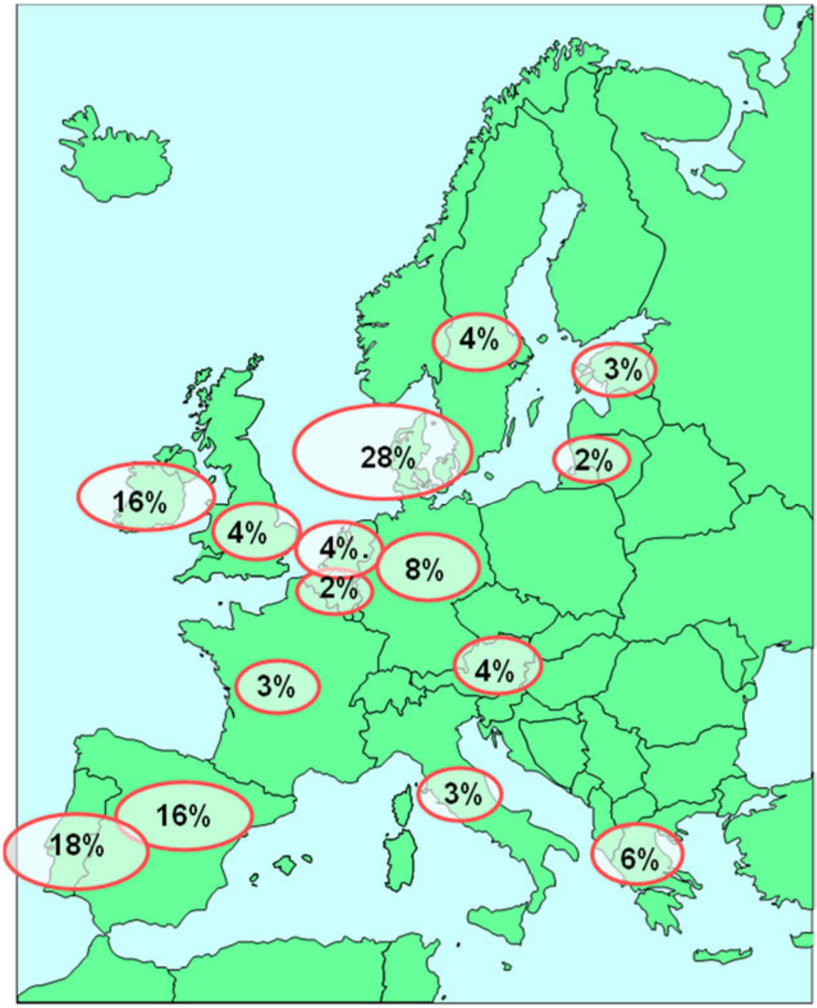


Figure 1. This map highlights penetration levels as a share of wind generation from total electricity consumption in 2011 in European countries that have reached a 2% penetration level. In the European Union (EU), the penetration level exceeded 5% in 2011; in the United States, the penetration level is approaching 3%; in Australia, it is 2.5%; and in China, it is 2% (Source for the penetration levels: IEA WIND 2012).

The national case studies address different impacts: balancing the power system on different short-term time scales; grid congestion, reinforcement, and stability; and power adequacy. Reasons underlying the wide range for wind integration impacts include definitions for wind penetration, reserves types, and costs; different power system and load characteristics and operational rules; assumptions on the variability of wind, generation mix, fuel costs, and the size of balancing area; and assumptions on the available interconnection capacity.

In many studies, estimates for integration costs are presented. 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. In most case studies, a comparison with other alternatives to wind has not been studied. When estimating the costs, allocation of system costs like new grid or reserve capacity to wind power can differ. It is challenging to allocate system costs for a single technology because the system services are there for all grid users, and integration cost is not observable. This inability to observe integration cost has resulted in multiple indirect methods for estimating it. In the case of an increased balancing requirement, 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 to adding wind power to power systems: it reduces the total operating costs and emissions as wind displaces fossil fuel use. When considering the question of integration costs, it is also important to keep in mind that all generation sources, including nuclear and fossil plants, have costs associated with managing them on the grid.

The case study results are summarised in four sections: first, Chapter 2 provides updated information on the variability and uncertainty of large-scale wind power, from reported experience. Chapters 3–6 summarise results: Chapter 3 for reserve requirements, Chapter 4 for balancing costs and impacts to conventional generation, Chapter 5 for effects on the transmission grid, and Chapter 6 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. Chapter 7 lists system operation practices and technologies that mitigate unfavourable impacts and support enhanced penetration. Chapter 8 contains conclusions and discussion. Appendix 1 provides a summary of on-going research in the national projects contributing to Task 25.

2. Wind power variability and uncertainty

This chapter introduces the characteristics of variability and uncertainty in wind power from experience of measured data from large-scale wind power production and forecasting. This data is important as an input to integration studies. There is a significant smoothing effect in both variability and uncertainty of wind power when looking at power system wide areas. The variability and forecast errors per unit are reduced with larger geographic dispersion. The uncertainty of future wind power production will further be reduced as more accurate forecasting methods are developed. Inability to capture this smoothing effect will impact the estimates for wind impacts on power systems.

Variability in wind power generation causes changes to the operation of conventional generation fleet, reducing operational hours as the wind power penetration increases, and increasing ramping and starts/stops. It may also alter demand patterns as so far as demand is or will be more flexible. Uncertainty leads to changes in shorter time scales (i.e., ramping) and can necessitate changes in operational conventions, such as reserve and market structures to enable shorter response time from the conventional generation fleet.

2.1 Variability of large-scale wind power production

Variability in wind power generation is mainly caused by pressure gradients in the atmosphere and by turbulence in the wind fields. Turbulence is visible in the output of individual wind turbines, but tends to disappear from the output of large-scale wind power generation, because turbulence is not correlated over longer distances. Pressure gradients are correlated over a long distance since they are dependent either on high- and low-pressure areas or on temperature differences prevalent in specific conditions (e.g., land-sea breeze). Hence, wind power generation is not random; it is correlated with itself over time and space (i.e., autocorrelation and cross-correlation).

Cross-correlation makes the presentation and comparison of variability difficult. Variability includes at least the frequency of different generation levels, the frequency and the size of output changes (ramps), and the duration of events, which may be ramps or periods of relatively stable generation. In general, geographically concentrated generation will be more variable than well-dispersed generation.

Examples of smoothing effect are presented as duration curves for wind power production from different size areas. These plots show how often different levels of production occur, by plotting the hourly production during 8760 hours of one year in descending order. Figure 2 displays the impact of larger geographic area on the frequency of different output levels. In the figure, the combined generation from several countries is rarely more than 50% and is usually more than 5% of installed wind capacity. Generation from smaller geographical footprints displays higher extremes and more output variability.

Figure 3 displays 1-hour ramps in the same areas. Hourly ramps clearly decrease as the area size increases. The extremes in the 2-year data set are within 5% of the installed capacity. Figure 4 demonstrates that ramps in shorter time scales are limited, but that in the 12-hour time scale, the ramps are getting close to the actual range of output even for well-dispersed wind generation (the output for all of Germany varied between 0.3% and 83.3% of nominal capacity). In the data set with 15-minute average generation, the fastest ramps were 0.31% per minute and -0.28% per minute.

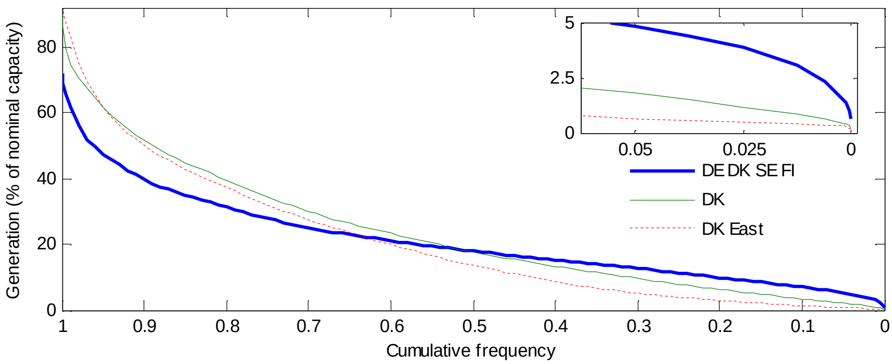


Figure 2. Aggregating wind generation over larger geographic areas decreases the number of hours of zero output and reduces the maximum power as relative to installed capacity. Cumulative frequency (i.e., duration curve) of wind power generation in areas with different size: Eastern Denmark; Denmark; and a combined area of Germany, Denmark, Sweden, and Finland (assuming an equal amount of wind power in Denmark, Sweden, and Finland while Germany has as much as the other countries put together). The inset displays the tail of the distribution more closely.

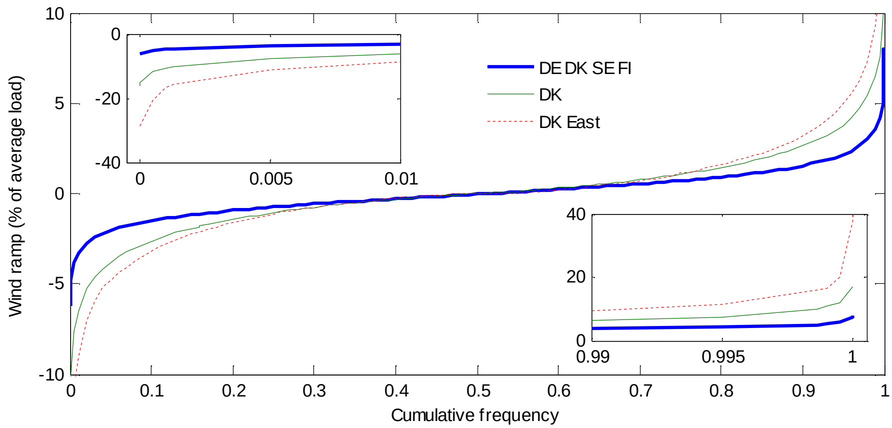


Figure 3. Smoothing effect of wind power reduces high wind ramps when area size increases as seen from cumulative frequency of 1-hour ramps in wind power generation. The insets display upward and downward tails of the distribution more closely. (DK Denmark, DE Germany, SE Sweden FI Finland).

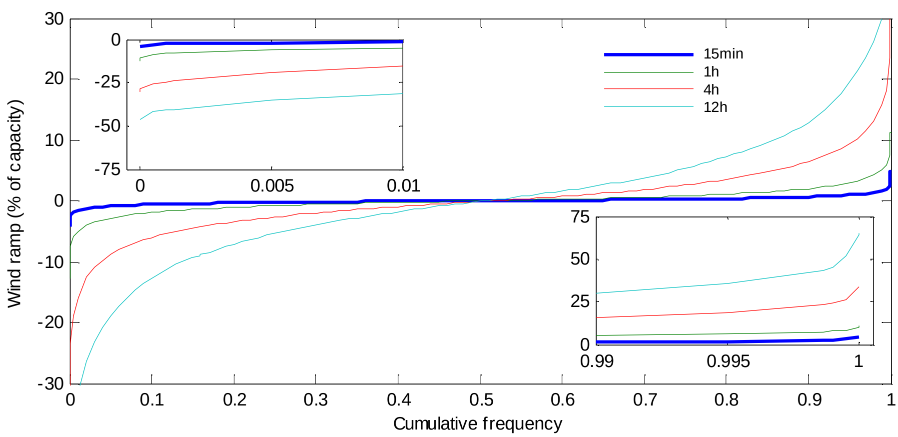


Figure 4. Smoothing effect reduces variability more at shorter time scales, as seen from cumulative frequency of ramps of different time scales in Germany for 2010–2011.

The Task 25 analyses (Holttinen et al., 2011a), using 10- and 15-minute data for six European countries (Denmark, Finland, Germany, Ireland, Portugal, Spain) and two U.S. states, show that the ramp rates of wind power at exceedence levels of 99.95% and below are significantly smaller in 10- or 15-minute data than in hourly data. Comparisons show that using less wind power plant data (10–30 sites in a large area covering several hundred kilometres east-west and north-south) will overestimate the variability. Also, simulated data, even with plenty of sites with wind speed measurements, show more variability than measurements of actual generation. Analyses of the timing of largest ramps show that at 20%, wind penetration largest ramps are clearly increased and a further increase of wind power penetration will see large ramps occurring at times not experienced today.

The maximum variations recorded from measured wind power production data from countries in different time scales are presented in Table 1. Storm events can result in extreme variation from wind power when wind speeds are high enough to require wind turbines to shut down from full power (to protect the wind turbine). These events are quite rare and usually occur 1–2 times in 1–3 years, depending on location. Because large storm fronts take 4–6 hours to pass over several hundred kilometres, aggregation of wind capacity turns the sudden interruption of power into a multi-hour downward ramp. Short-term forecasts of wind power are critical in managing these situations. Large wind power plants can be required to operate at partial loads during storm events to prevent large ramps. The impact can also be reduced by changing the controls of wind turbines: preventing all turbines from shutting down during the same minute, and reducing the output more slowly as winds increase over cut-out wind speeds. Extreme ramp rates recorded during storms are as follows:

- **Denmark:** On January 8, 2005, Denmark experienced 2000 MW (83% of capacity) decrease in 6 hours, or 12 MW (0.5% of capacity) in a minute (Eriksen et al., 2005). Regarding offshore wind power, the ramps can be higher: 209 MW (5.5% of total wind capacity or 24.4% of offshore wind capacity) decrease in 55 minutes on November 11, 2010, and in 40 minutes on February 7, 2011 (Cutululis et al., 2011).
- **Germany:** There were six larger ramping incidents in 2011, lasting for several hours. The most extreme was August 19, when a total of 8419 MW (31%) was lost in 5.5 hours, resulting in ramp rates of 25.5 MW/minute and 1531 MW/h (5.6% of installed capacity in an hour). The highest upward ramp lasted for almost 10 hours with a total increase of 10831 MW (18.5 MW/minute, 1111 MW/hour) (Source: TSO Amprion).
- **Portugal:** A storm on November 15, 2009, caused a 2.42 GW steady increase of wind power production during 5.5 hours (72% of installed wind capacity). Due to the storm, two grid fault incidents occurred in which larger than 1.3 GW, respectively 51% and 52% of the wind generation, was lost and each was recovered in less than 15 minutes (the average ramp rate was -484.8 MW/h). During the Klaus storm of January 2009, total wind power capacity was decreased from 1200 MW to 400 MW in 6 hours, at a maximum ramp of 200 MW/h (approximately 7% per hour).
- **Spain:** Examples of large ramp rates recorded for approximately 21 GW of wind power in 2011 include an 8860 MW (86%) increase in 8 hours (with a ramp rate of 1108 MW/h, approximately 47% of capacity), and a 4230 MW (42%) decrease in 4 hours (with a ramp rate of -1057 MW/h, 20% of capacity). Generated wind power between 25 MW and 16636 MW has occurred

(0.2–79% of capacity). The most severe storm incident was the extra-tropical, mid-latitude cyclone Klaus on January 23–25, 2009, resulting in the disconnection of many wind power plants in northern areas of Spain, leading to a reduction of approximately 7000 MW of wind power in approximately 7 hours (less than 50% of installed capacity) (Source: REE).

- **Quebec:** A large ramp rate was recorded in December 2011 with 600 MW in 5 hours (65% of capacity) or 14% per hour.
- **Italy:** (Sicily island where the installed wind capacity has increased from 1391 MW for 35 wind power plants in 2010 to 1562 MW for 42 wind power plants in 2011): In the period 2010–2011, Italy recorded a maximum decrease of 1024 MW (approximately 75% of installed wind capacity) in 12 hours on December 20, 2010, and a maximum increase of 907 MW (approximately 71% of installed wind capacity) in 12 hours on October 18, 2010 (Source: Terna).

Table 1. Extreme variations of large-scale regional wind power, as a percent of installed capacity. Denmark, Portugal. Germany and Sweden data 2010–2011 from TSOs web pages (http://www.energinet.dk). Ireland 2011 data from EirGrid. Italy (Sicily island) data 2010–2011 from Terna, Finland data 2005–2011 from VTT. U.S. data 2007–2011 from NREL. The BPA data are mostly from sites inside an area of 60 x 60 km^2.

			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			-16%	+17%	-38%	+46%	-72%	+78%
East Denmark	200x200 km^2	>100			-29%	+44%	-58%	+54%	-81%	+85%
Ireland	280x480 km^2	>50	-17%	+15%	-29%	+25%	-56%	+53%	-87%	+76%
Italy (Sicily island)	25.711 km^2	>35	-49%	+46%	-50%	+49%	-58%	+47%	-75%	+71%
Portugal	300x800 km^2	>100			-15%	+20%	-41%	+59%	-63%	+68%
Germany	400x400 km^2	>100	-4%	+5%	-13%	+11%	-30%	+34%	-47%	+65%
Finland	400x900 km^2	30			-22%	+24%	-52%	+44%	-70%	+78%
Sweden	400x900 km^2	>100			-10%	+12%	-28%	+36%	-50%	+57%
US Texas	490x490 km^2	25–55			-37%	+35%	-59%	+58%	-75%	+69%
US BPA	300x200 km^2	8–37			-38%	+49%	-65%	+86%	-89	+93%

The sub hourly changes have been collected from several countries as standard deviation value of the variations (Söder et al., 2012), in Table 2 and Figure 5.

These show how the variability decreases as the area size increases, and also that the variability of shorter time scales (here, 10 minutes) smoothes out smaller areas than the longer time scale changes.

Table 2. Wind power changes of total wind power production for four different time periods, measured as standard deviation of the variations time series, presented as a percent of installed capacity. *15-minute data for Spain are obtained from linear interpolation using 10-minute and 30-minute data. (Söder et al., 2012)

Country / Area	**Wind**	**Standard Deviation – σ [percent]**			
	MW	**5 min**	**10 min**	**15 min**	**30 min**
Sweden - Gotland	110	1.4		2.9	4.5
Denmark – 1 region	251	1.4		2.3	3.7
West Denmark	2,839	0.6		1.1	1.8
Denmark	3,801	0.5		1	1.7
Spain – 1 power plant	31		4.0	4.6 *	6.4
Spain – 9 power plants	282		1.7	1.9 *	2.4
Spain	19,635		0.4	0.6 *	0.9
Ireland – Donegal	274			2.4	3.7
Ireland – SouthWest	747			1.4	2.4
Ireland – ROI	1,539			1.0	1.7
Portugal	3,357			0.9	1.6
Portugal – Zone A	65.6			3.7	4.2
Portugal – Zone E	382			3.8	4.9
Portugal – Zone G	504			2.0	2.6
Portugal – Zone I	105			5.6	7.1
Portugal – Zone J	113			4.8	5.5
Germany	9,677			1.1	1.8

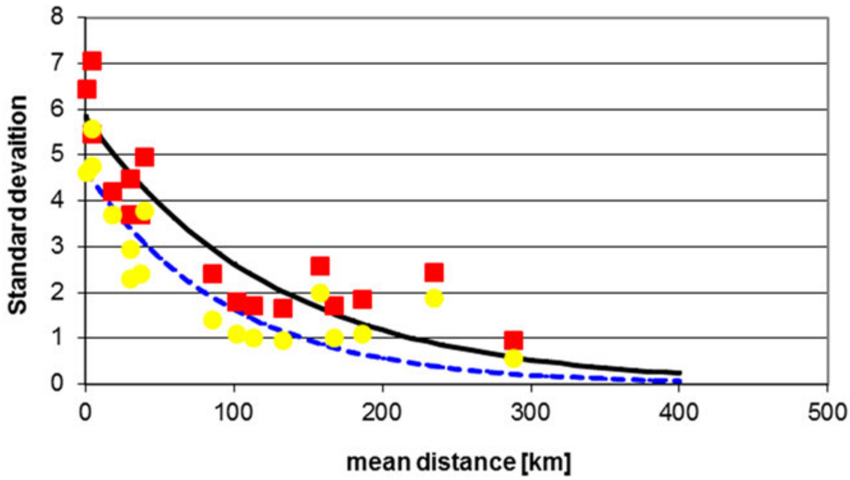


Figure 5. Standard deviation as a percent of installed capacity for 10-minute (circles), 30-minute (boxes), 10-minute fitted (dashed), and 30-minute fitted (straight line) change of total wind power as a function of mean distance between all wind power stations (Söder et al., 2012). Mean distance is calculated from a representative rectangle covering the area of the wind power plants.

2.2 Uncertainty of large-scale wind power

Wind energy forecasting can be used to predict wind energy variability in advance through a variety of methods based on numerical weather-prediction models and statistical approaches. Wind forecasting has been developed since the 1990s and is still developing (Giebel et al., 2011). The overall shape of wind generation can be predicted most of the time, but significant errors can occur in both the level and timing of wind generation. Wind forecast accuracy improves for shorter time horizons. There is a strong aggregation benefit for wind forecasting, as shown in Figure **6**, aggregation over a 500-km region reduces forecasting error by approximately 50%. A Mean Absolute Error (MAE) of 4% shown for 60 wind power plants is equal to the quality of the forecast for all of Germany. Typical wind forecast errors for a single wind power plant day-ahead are 8–12%. The analysis has shown that approximately 10–12 wind power plants spatially distributed over Germany are enough to achieve a representative forecast quality similar for all of Germany (Sensfuß et al., 2011).

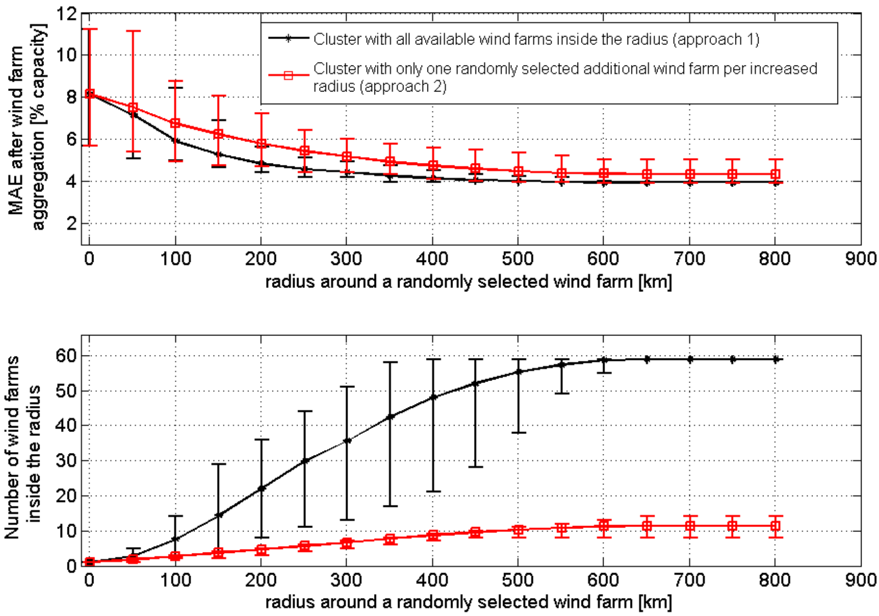


Figure 6. Forecast error reduction with area size; example from Germany where data from 60 wind power plants have been grouped, choosing one as a starting point and increasing the radius around it to take in more wind power plant forecast data. The upper graph shows the forecast error as MAE. The lower graph shows the number of wind power plants that have been aggregated per radius extension. The solid line corresponds to the mean value of the different runs with different "start" wind power plants. The error bars correspond to the variance of the different runs (Source: Sensfuß et al., 2011).

An example of forecast errors increasing as the time horizon grows is shown from Quebec (Figure 7).

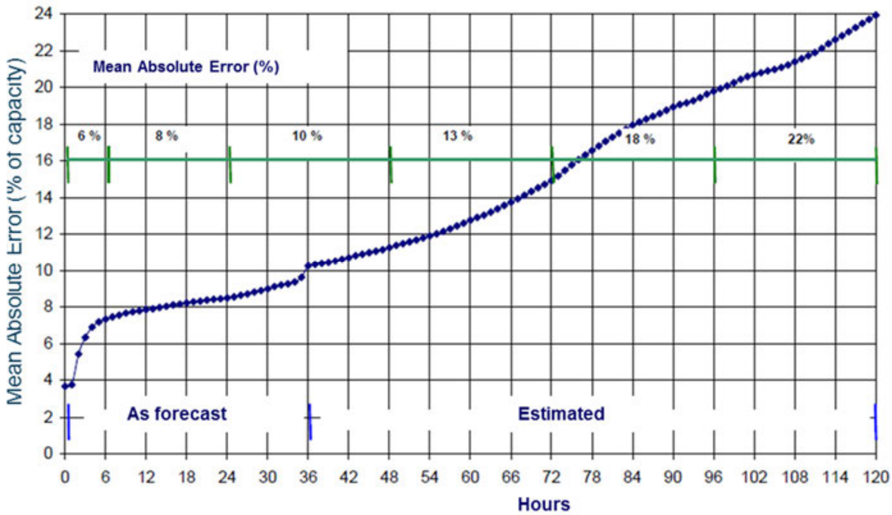


Figure 7. Forecast error increases over time horizon. Example from 4 wind power plants for a total of 450 MW and the maximum distance between them 250 km in Quebec (Source: Hydro Quebec).

The forecast errors are not normally distributed – there are more low errors and also large errors than in Gaussian distribution (Figure 8). The large, rare error events are challenging to catch when estimating the reserve requirement, for example.

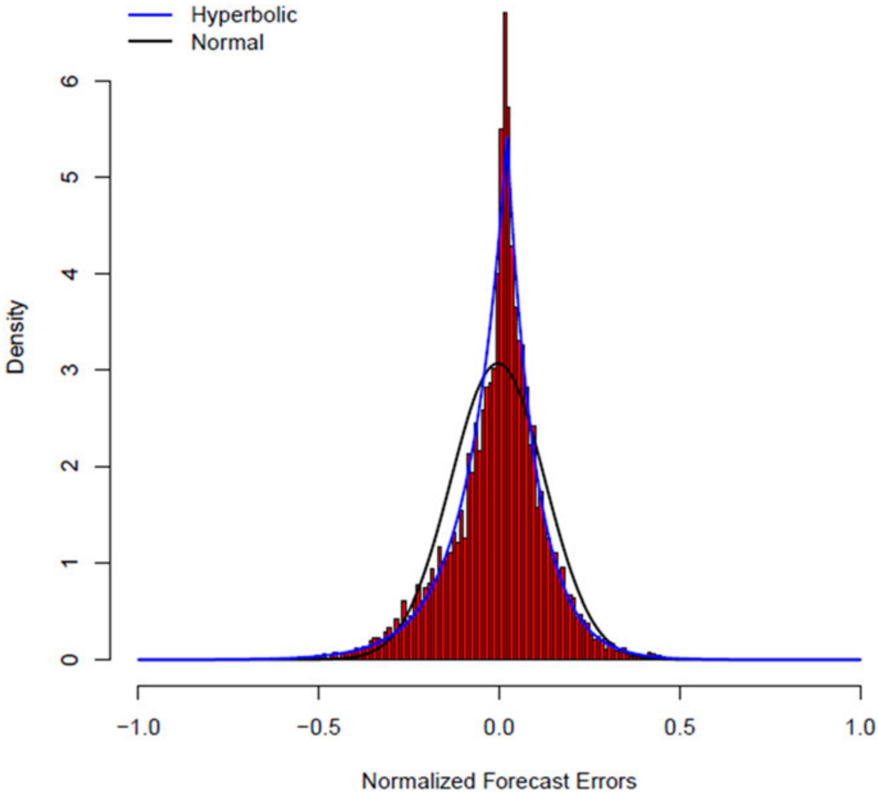


Figure 8. Wind forecast errors are not normally distributed. Example from California, United States, showing histogram of the day-ahead forecast errors for an approximately 970 MW distributed wind power plant, normalizsed based on total wind power capacity. The black line represents a normal distribution with the same mean and standard deviation. (Source: Hodge et al., 2012)

For the relatively new area of offshore wind, the forecasting needs improvements. The ability of forecasting systems today to predict a wind power plant stopping due to very high wind speeds is not very good. This could lead to very large wind power forecast errors, depending on the share of offshore wind in the system (Figure 9).

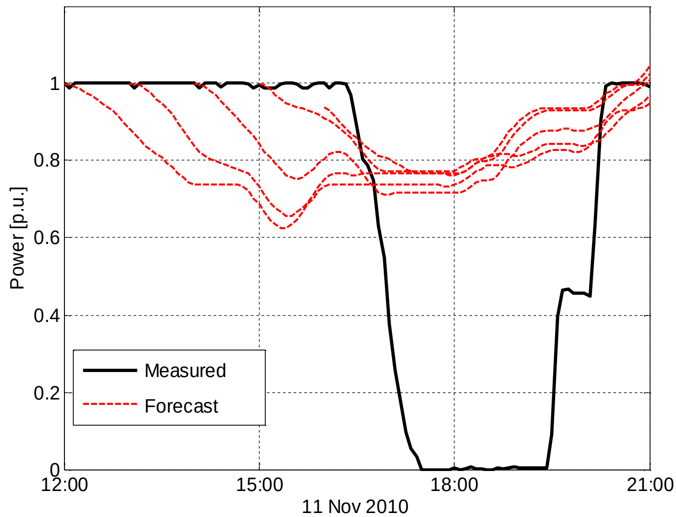


Figure 9. Measured wind power production and the intra-day forecasted wind power, based on the online measurement data and forecasts running every 15 minutes, during an extreme wind speed event in Denmark on November 11, 2010 (Cutululis et al., 2011). The measurements are for one wind power plant (Horns Rev 2).

3. Wind power impacts on reserve requirements

The operating reserve requirement addresses the short-term flexibility for power plants that can respond to load and generation unbalances. These are caused mainly by unpredicted variations. Also, any variability inside time step for dispatch (like inside 1 hour or 15 minutes) is managed with operating reserves. It is important to note that the reserves are operated according to total system net imbalances. This reduces the use for reserves considerably compared to balancing individual loads or generators.

All power systems have different terminology and classes of reserves responding at different time scales. Reserves are allocated (dimensioned and scheduled) for a diverse range of conditions. Reserve allocation also considers reserves responding across multiple timescales. A very general and robust classification divides reserves as:

1. operating automatically (fast reserves; for example, primary and secondary in Europe, and regulating reserve in the United States)
2. being activated manually when needed (from minutes to a few hours; for example, tertiary reserves in Europe and load-following reserves in the United States) (Holttinen et al., 2012).

The experience so far is that wind power has not caused investments to new reserve capacity. The experience in frequency control during challenging high-wind penetration incidents are reported in Söder et al. (2012):

- **Ireland:** Due to the nature of the Irish system (a small island system with little interconnection), reserve levels are determined with system flexibility in mind. No additional reserve was required during periods of high wind variability. However, frequency and voltage stability concerns have necessitated rules for the number of units that remain online (three units in Northern Ireland and five in the Republic of Ireland).
- **Spain:** The impact of wind power to automatic fast reserve has been very small, but the overall impact to manual reserves has already been significant. Using probabilistic methods to determine the reserve requirement has shown good results but still needs testing to gain confidence in the method

(Gil et al., 2010). One incident of low load and high wind has resulted in down regulation reserve to be exhausted (November 9, 2010, from 2:10 a.m. to 5:00 a.m. with 54% of the consumption fed by wind). This was resolved by TSO ordering some thermal power plants to shut down, and after that wind to be curtailed (Söder et al., 2012).

- **Portugal:** The 6 hours ahead forecast error for wind power can be 20% of the produced energy, however, this error is lower for larger productions (around 10 %). Because of that the reserve requirement/allocation has been increased by 10% of predicted wind power. That is managed by existing hydro and thermal power plants, and occasionally by reducing import from Spain (Ribeiro, 2012).

It is also important to note that the time steps chosen for dispatch and market operation can significantly influence the quantity and type of reserve required. For example, markets that operate at 5-minute time steps can automatically extract significant balancing capability from the generators' that must ramp to achieve proper position for the schedule for the next market period (Kirby & Milligan, 2008).

There are several methods that can be used to calculate the impact of wind generation on operating reserves. The computation of reserve requirements requires estimates of the uncertainty and variability of demand, wind generation, and other generation as inputs. For wind power, the forecast horizon time scale is a crucial assumption because the uncertainty will reduce more significantly than for demand at shorter time scales. A common approach is to compare the uncertainty and variability before and after the addition of wind generation. Adding wind generation means allocating additional reserves to maintain a desired reliability level. (Holttinen et al., 2012)

The results presented in Figure 10 for increase in reserve requirements due to wind power are from following studies:

- Canada/Hydro Quebec (Robitaille et al., 2012)
- Germany (Dena, 2005; Dena, 2010; Dobschinski et al., 2010)
- Ireland (AIGS, 2008, Workstream 2B)
- NL (Holttinen et al., 2012)
- Sweden (Axelsson et al., 2005)
- UK (Strbac et al., 2007)
- US/Minnesota 2006 (EnerNex/WindLogics, 2006)
- US/New England ISO (NEWIS, 2010).

The large range of results is mainly due to different time scale of uncertainty taken into account in the estimates. If only hourly variability of wind is taken into account when estimating the increase in short-term reserve requirement, the results are 3% of installed wind capacity or less, with penetrations below 20% of gross demand. When 4-hour forecast errors of wind power are taken into account, an increase in short-term reserve requirement of up to 9–10% of installed wind capacity has been reported, with penetration levels of 7–20% of gross demand. The highest results in Figure 10 are from a study in which 4-hour variability of wind (not forecast error), combined with load forecast error, results in a 15% reserve requirement at 10% penetration and an 18% reserve requirement at 20% penetration of gross demand (Strbac et al., 2007).

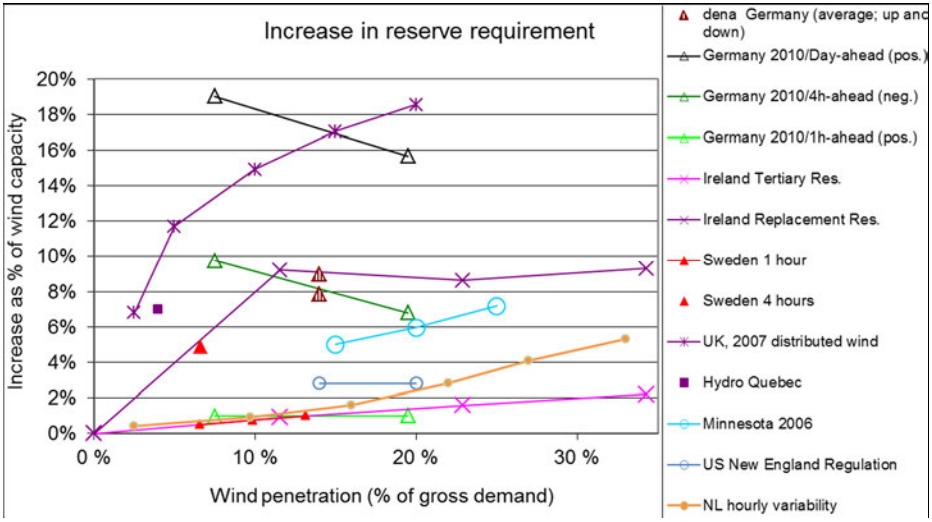


Figure 10. Results for the increase in reserve requirement due to wind power, as relative to wind penetration level. German 2010 estimates show the difference between different time scales of uncertainty: taking into account the day-ahead, 4-hour-ahead or 1-hour-ahead forecast errors. In the Minnesota, dena Germany, Ireland Replacement Reserve, and Hydro Quebec estimates, the day-ahead uncertainty has been included. UK results combine the variability of wind 4 hours ahead (with no forecasting) to forecast errors of load. For the others, the effect of variations during the operating hour is considered.

The German calculations show that if day-ahead forecast errors are balanced with the short-term reserves, the increase in short-term reserve requirement can be very high. In an earlier German study (Dena, 2005), the reserve requirement was taken as the average impact of day-ahead forecast errors of wind power, showing values of nearly 10% in Figure 10. Using the maximum values would result in an increase that is 15–20% of installed wind capacity (Dena, 2005). It can be assumed that the wind power forecast will also improve in the future. The German dena grid study II (Dena, 2010) estimates the positive and negative automatic (secondary) and manually activated (minute) reserve for the year 2020 and assumes that the forecast error will decrease by 45% compared to 2008. It is assumed that only 1-hour-ahead forecast errors are balanced by these reserves. The study concludes that for a wind power penetration of 27%, the “balancing energy which must be provided in 2020 […] is roughly equal to the current demand,” where the wind penetration in 2010 was 6%.

For Ireland, the impact of increased wind power capacity on reserve requirements has been calculated in All Island Grid Study (AIGS, 2008) Workstream 2B using the methodology described in Doherty & O'Malley, (2005). This approach quantifies the amount of reserve for each category that is required to ensure that the expected number of load-shedding incidents in a year is less than a certain threshold, considering the combined probabilities of generator loss, wind forecast error, and load forecast error. The results show that the requirement for primary operating reserve (time scale seconds) does not increase significantly with increased wind capacity. There is, however, a significant increase in the tertiary reserve requirements, as shown in Figure 10, assuming a 1-hour forecast horizon (scheduling in Ireland is based, at best, on a 4-hour-old forecast).

For Hydro Quebec, the hourly reserve (Automatic Generation Control AGC and load-following reserve) is evaluated based on a method that allocates these reserves differently than most other studies. When adding wind to the system, most analysts calculate the incremental increase in reserve needs that are caused by wind energy. Conversely, the method employed by Hydro Quebec allocates reserves to load and wind based on a variability allocation. This approach results in the load share of reserves declining after wind is added to the system, which allocates more reserve to wind than an incremental method would. However, because of the capabilities of the hydropower system in Quebec, additional reserve for wind is not needed (Robitaille et al., 2012).

Independent System Operator New England (ISO-NE) in the United States uses three main types of operating reserves: 10-minute spinning and non-spinning reserve, and 30-minute operating reserve. In the recent wind integration study, these categories of reserves were estimated dynamically, based on the behaviour of the wind plants. Similar to other U.S. studies, this dynamic reserve was based on wind variability and uncertainty, and the alternative levels of variability at each level of output (see EWITS, 2010; Ercot study, GE, 2008; and SPP integration study CRA, 2010). Although results vary somewhat from study to study, the ISO-NE results are fairly typical of U.S. studies. For example, the Southwest Power Pool study (CRA, 2010) finds an increase in summer regulation requirements from wind power to be approximately 100–150 MW at a 20% penetration (approximately 14 GW of wind capacity), depending on the load level. CRA partitions the year and finds that regulation impacts are similar, but not the same, at different times. NEWIS (2010) finds that ISO-NE can use some additional 10-minute spinning and non-spinning reserve to help manage wind. Depending on scenario, the range of spinning reserve at a 20% penetration averages between 193 MW and 261 MW, for a wind capacity of approximately 8,100 MW (the installed capacity varies by the sites selected to meet the energy target). The lower penetration level with approximately 6.5 GW gives similar results. ISO-NE results in Figure 10 are based on the average regulating reserve across multiple scenarios at the given penetration rate.

Because wind power output varies, it is now widely recognized that wind-induced reserves can be calculated dynamically (i.e., the reserve depends on how strong the wind is). For example, if wind power is at (or near) 0 MW, there is no need for up-reserve because the wind output cannot fall. Conversely, if the wind is at (or near) maximum output, it cannot increase, and therefore there is no need for down-reserve. If the reserve requirement is estimated once per day for the next day instead of using the same reserve requirement for each day of the year, the low wind days will induce less requirements for the system and, thus, the reserve allocation can be increased only for days when wind variability and uncertainty are at their highest (Holttinen et al., 2012). An example from results from dynamic allocation of reserves is shown in Figure 11 from the U.S. study King et al. (2011), which is based on a method developed for the Eastern Wind Integration and Transmission Study (EWITS, 2010).

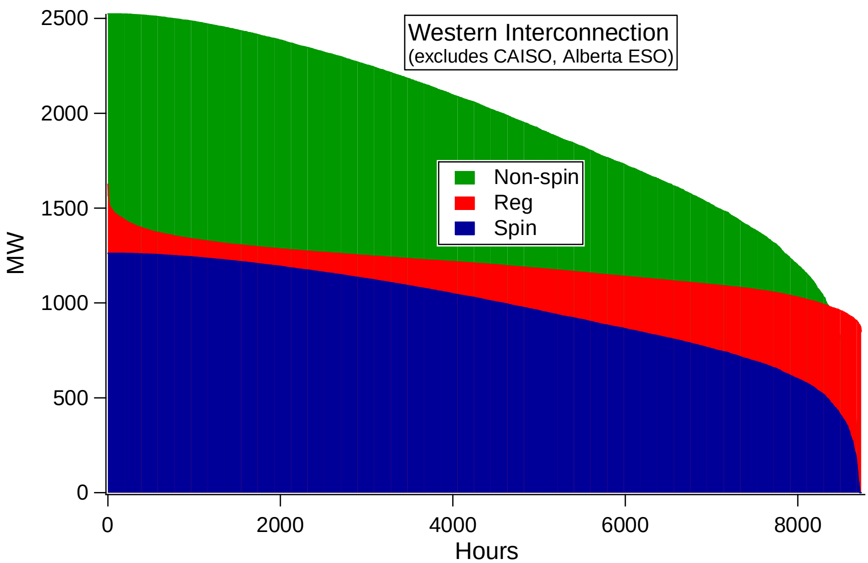


Figure 11. One-year duration curve of dynamic reserve calculation, showing all three types of reserves calculated (adapted from King et al., 2011).

Avoiding allocation of unnecessary reserve is cost effective and can be needed in higher penetration levels of wind power. In Spain and Portugal, new ways of allocating reserves have been tested by TSOs and compared with the actual use of reserve (Figure 12) (Holttinen et al., 2012; Bessa et al., 2012). Probabilistic reserve allocation was estimated for Denmark in EU-project SUPWIND (Apfelbeck et al., 2009).

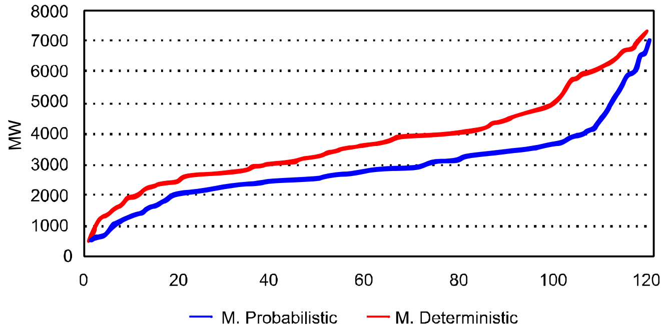


Figure 12. Reserve calculated and actually deployed during hourly peak load period over 120 days of operation (Source: Gil et al., 2010).

As the use of dynamic reserve calculations increases, a more standard approach to reporting the results is clearly needed. For example, the California Independent System Operator (ISO) (Loutan & Hawkins, 2007) produced estimates for regulation (primary/secondary reserve) that are approximately 100–500 MW or 1–5% of installed wind capacity; however, these are maximum values that are taken from a dynamic calculation where reserve is a function of the current wind output level. Other results for wind power impacts on this fast response automatic reserve type are very low (e.g., 10 times lower than results in the CEC study performed by GE, see Porter, 2007). This is because the reporting of results is not comparable. Statistical characterizations that include multiple parameters, such as the mean, maximum, minimum, and standard deviation, or the use of annual duration curves can help accurately communicate the reserve characteristics from the analyses. An example of multiple ways that reserves can be reported appears in King et al. (2011).

Increasing reserve requirement is usually calculated for the worst case. Even if the worst case shows increase, this does not necessarily mean new investments for reserve capacity, but rather generators that were formerly used to provide energy could now be used to provide reserves (see Kirby & Milligan, 2009).

Task 25 analyses on variability data from six European countries and two U.S. states show that the impact of wind variability on the system, when compared with load variability, is relatively small at smaller penetration levels and only after penetration levels of 5–10% extreme ramping starts to increase more when adding wind (Figure 13). There is a slight tendency that the impact of wind starts at higher penetration levels for 15-minute ramping than for hourly ramping data. This indicates that the wind variability will smooth out more when the time scale is reduced, compared with load variability (Holttinen et al., 2011a).

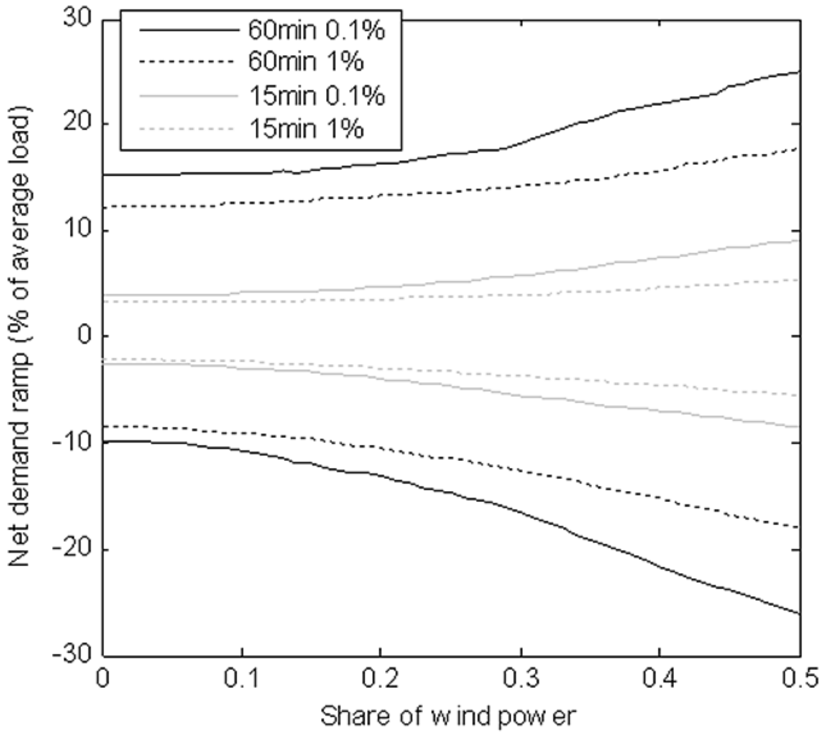


Figure 13. Extreme ramps in net load are growing with increasing wind penetration level. Example from Germany, showing positive and negative ramps presenting 0.1% and 1% of exceedence level, and comparing 15-minute and 60-minute data.

4. Balancing costs and impact on conventional generation

The variability and uncertainty of wind power will impact the operation of a conventional power plant. Changing the output level of the plant, additional ramping, and increasing amount of starts/stops will incur costs. To assess the impact of wind on the operation of power systems, simulation model runs are made that optimise the dispatch of all power plants to meet varying load.

Most results on balancing costs are based on comparing costs of system operation without wind and adding different amounts of wind. It is challenging to extract system balancing costs from total operational costs, including fuel costs. Any alternative to wind would also influence fuel costs (and adding large amounts of wind may also impact prices for fossil fuels). The costs of variability are also addressed by comparing simulations with flat (constant) wind energy to varying wind energy (for example, in Minnesota in the United States and Greennet Germany and Nordic countries). However, this method has not proved to be accurate because the market value during different times of the day are also influenced by the assumption of the alternative to wind in the simulations, so the difference in costs is not only due to variability (Milligan et al., 2011).

The results presented in Figure 14 for increase in balancing costs due to wind power are from the following studies:

- UK (Ilex Energy & Strbac, 2002; Strbac et al., 2007)
- Ireland (SEAI & EirGrid, 2011)
- Colorado (Zavadil & King 2008)
- Minnesota (EnerNex/WindLogics, 2004 and 2006)
- California (Shiu et al., 2006)
- Nordic countries and Germany, Greennet (Meibom et al., 2009).
- US Eastern Wind Integration Study (EWITS, 2010), which has three scenarios for the 20% penetration level; in Figure 14, the lowest result was used (results for 20% penetration level: \$5.77/MWh, \$7.21/MWh, and \$8.00/MWh; results for 30% penetration level: \$7.07/MWh).

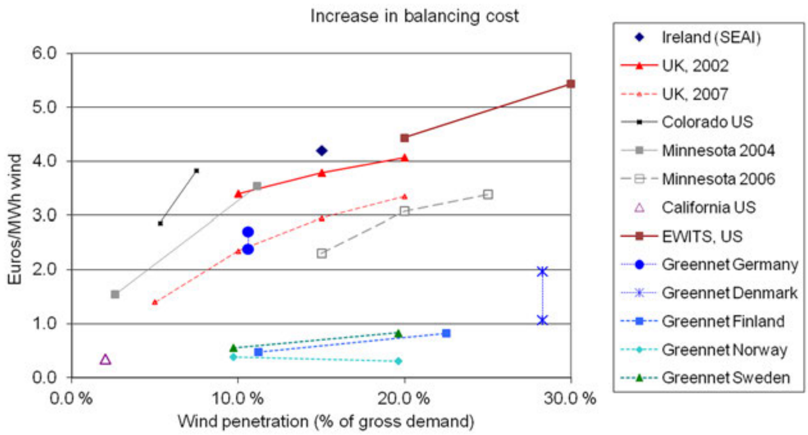


Figure 14. Results from estimates for the increase in balancing and operating costs due to wind power. The currency conversion used here is 1 € = 0.7 £ and 1 € = 1.3 US$. For the UK, 2007 study, the average cost is presented here.

The highest estimates for reserve requirements from Germany and the UK are not reflected in balancing costs – for both studies, it was concluded that the increased amount of reserve can be handled with the current conventional power plants. For the UK, only the increased cost of operating existing reserves has been estimated.

For wind penetrations up to 20% of gross demand (energy), system operating cost increases arising from wind variability and uncertainty amounted to approximately 1–4.5 €/MWh. This is 10% or less of the wholesale value of wind energy. It can be seen that there is considerable scatter in results for different countries and regions. The following differences have been noted:

- *Different time scales used for estimations:* For the UK 2002 study, the increased variability to 4 hours ahead has been taken into account. For the U.S. studies, the unit commitment impact for day-ahead scheduling is also 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.

- *Larger balancing areas:* The Greennet, Minnesota 2006 and EWITS studies incorporate the possibilities for reducing operation costs through power exchange to neighbouring countries/markets, whereas Colorado, California, PacifiCorp, UK, and Ireland 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. Larger power systems make it possible for smoothing of the wind variability.

- *Amount of wind power in neighbouring countries:* Greennet results for Denmark and Germany show that different costs result depending on how much your neighbours have wind power. The higher costs refer to a situation in which Finland, Sweden, and Norway have 20% penetration. The Norway results show that its flexibility is so high that there is no increase in operating costs when increasing wind penetration; the line is flat.

In addition to estimates, there is already some experience from the actual balancing costs for the existing wind power in Denmark and Spain. 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). In Spain, the balancing cost for wind power has decreased in recent years, from 1.53 €/MWh in 2010, 1.40 €/MWh in 2011, and 1.30 €/MWh during the first 9 months of 2012 (based on data from Spanish Wind Energy Association, 2012). The penetration level has been approximately 16%. In a recent report from the Netherlands, balancing costs for wind in the Netherlands using balancing market data is estimated to be 0.6 €/MWh at a wind energy penetration level of 4% (Nieuwenhout & Brand, 2011). These numbers are in the middle of the estimated balancing costs in Figure 14.

The interconnection capacity to neighbouring systems is often significant. Thus, it is essential to note in the study setup whether or not the interconnection capacity can be used for balancing purposes. A general conclusion is that if interconnection capacity is used for balancing purposes, then the balancing costs are lower compared to the case in which they are not 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. Kiviluoma et al. (2012) details these and other relevant issues for short term energy balance when analysing future systems with large amounts of variable generation.

Figure 15 provides a summary comparison of wind integration costs from a number of wind integration studies in the Pacific Northwest region of the United States with results from a number of ISO regions. The primary differences between the studies is that the northwest entities represent a number of smaller balancing areas, operating with hourly schedules in bilateral markets, while the ISO markets represent large geographical regions with sub-hourly markets. It is evident that utilities in the Northwest estimate higher than average costs compared to the ISO market regions.

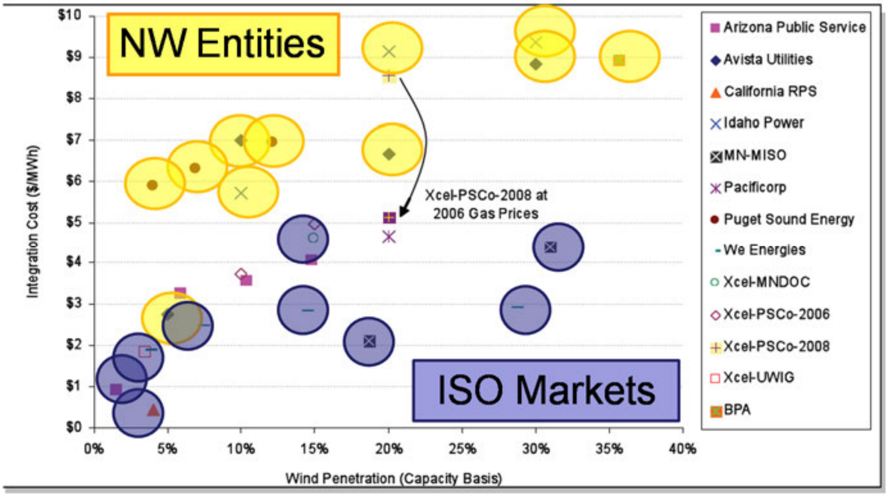


Figure 15. Integration cost estimates from U.S. wind penetration as installed wind capacity relative to peak load. The smaller balancing areas marked with yellow have larger costs. (Source: Portland General Electric & EnerNex, 2011)

Not all case studies presented results quantified as MW of increase in reserve requirements or monetary values for increase in balancing costs. Below are some short summaries of results related to electricity markets, hydropower and wind, and general system studies.

Balancing costs from electricity markets:

- Balancing market integration for Nordic, Germany, and the Netherlands in cases of future high penetration of wind power was estimated to reduce activated reserve by 24% due to imbalance netting. The annual expected operational cost saving would be approximately 512 million €, which is 30% of the system balancing cost. In order to draw the imbalances in the system, the wind forecast errors for 3 hours ahead are selected instead of 24 hours. Dynamic allocation of balancing exchange (on a daily basis) for the high-voltage direct current (HVDC) link between Norway and Denmark would reduce annual procurement cost by 5.93 million € compared to fixed allocation (on an annual basis). This illustrates the socio-economic losses in reserve procurement imposed by fixed reservation of the corridors for reserve exchange (Farahmand, 2012).
- In Sweden and Finland, the balancing costs as payments for wind power producers have been estimated from the balancing market (Nordic Regulating market) prices to be 0.3–3 €/MWh, depending on how distributed the wind power is and on the market price level for balancing (Holttinen & Stenberg, 2011; Neimane & Carlsson, 2008; Carlsson, 2011). These balancing costs only include the costs related to unpredictability because wind power variability is handled in the Nordic day-ahead market. In Sweden, the use of 15-minute 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 of 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 (with 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, 2012) and Sweden (Neimane & Carlsson, 2008). The conclusion is that at least for lower penetration levels and 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). It is clear that at higher penetration levels, correcting at least a larger forecast error closer to delivery would be worthwhile from the producer's point of view, and reduce impacts for the system (Holttinen, 2005).
- 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 combined cycle gas turbine CCGT during peak demand and for base-load coal during low demand (Ummels, 2009).

Wind impacts on balancing in hydropower dominated systems:

- Hydropower with large reservoirs has the potential to provide balancing for larger amounts of wind power. Changes in the utilisation of the Norwegian hydro reservoirs due to balancing future North Sea offshore wind are manageable. The Norwegian reservoir size of approximately 85 TWh is nearly half of the total installed reservoir size in Europe. The hydropower system benefits from higher HVDC capacities because Norway can import more wind energy, especially in periods of low prices in the continent and UK power market. As a result, water can be stored in the reservoirs, so hydropower can be exported in periods of high prices in the continent and the UK (Völler & Doorman, 2011).
- In Sweden, the capability of hydropower to balance various amounts of wind power in Northern Sweden was studied (Amelin et al., 2009). The existing hydropower in Northern Sweden has sufficient installed capacity and is fast enough to balance at least up to 30 TWh of wind power (i.e. 20% of gross demand). An important aspect is that Sweden has comparatively strong interconnections with its neighbouring countries.
- Several countries indicate the increase of the energy storage capacity using pumped hydro stations (PHS) (Portugal, Spain, Norway, Norway) and

other forms, such as heat storage (Finland and Sweden) as a means to integrate more wind generation when penetration is already high, typically above 15% (Estanqueiro et al., 2012a and b). However, an optimized articulation of the operation of PHS and wind generation would require the design of new market operation principles.

Other balancing results from system studies:

- 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 (Eriksen & Orths, 2008; Orths & Eriksen 2009). The new targets set in 2012 by the Danish Government aim for wind power to deliver 50% of electricity consumption by the year 2020.
- The Irish All Island Grid Study shows that going from 2 to 6 GW of wind, the operational costs of the electricity system fall by 13 €/MWh when compared to the base case. Due to the cost benefit approach in the study, the cost component was not published as such (AIGS, 2008). A joint study by SEAI and EirGrid simulated the 2011 All Island System with and without wind, and the constraints costs in both cases were compared (SEAI & EirGrid, 2011). This comparison showed that 2.2 GW of wind power increased constraints costs by 24 million € or 4.2 €/MWh. The study showed that this increase in constraints costs, along with subsidy costs, was offset, almost equally, by decreased wholesale market prices resulting in a neutral net cost difference overall.
- The Western Wind and Solar Integration Study (WWSIS) found that the Western Interconnection of the United States could accommodate up to 27% wind and solar energy penetration if operational changes could be made, including Balancing Area (BA) cooperation and intra-hour scheduling between BAs. While additional flexibility reserves were not needed for the wind variability, they were needed for the wind uncertainty to cover extreme forecast errors. Because it is hard to predict when an extreme forecast error will occur, and because holding high levels of flexibility reserves 8760 hours of the year for only 89 hours of events per year is cost-prohibitive, it was determined that an additional 1300 MW of demand response that could respond to contingencies would provide a more cost-effective approach to system balancing (GE Energy, 2010).
- The Western Wind and Solar Integration Study WWSIS found that as wind and solar are initially added to the grid (0–15% energy), there were fewer cold starts of fossil plants. As wind and solar penetrations increase (above 15%), the number of fossil plant start-ups increases significantly, especially cold starts (Jordan, 2012). However, WWSIS, as is the case for most other studies, did not explicitly include wear-and-tear costs for cycling and ramp-

ing of fossil plants because this information was not publicly available. Therefore, the amount of cycling and ramping may be overestimated in these studies. Phase 2 of WWSIS determines wear-and-tear costs and impacts for cycling and ramping of fossil plants (Kumar, 2012). These costs are being included in the unit commitment and economic dispatch optimization for several scenarios. This new cost data was applied to the original WWSIS dispatch results to determine a ceiling for these wear-and-tear costs. At 27% wind and solar energy penetration, the ceiling wear-and-tear cost was $140–470 million, or $0.55–1.90/MWh of wind and solar energy produced. This is 0.7–2.4% of the value of wind and solar energy (Jordan, 2012).

- The Eastern Wind Integration and Transmission Study (EWITS, 2010) calculated the impact of 20% and 30% wind energy in the Eastern Interconnection of the United States. The three 20% cases were constructed based on alternative mixes of high-capacity-factor wind locations, geographically distributed wind locations, and offshore wind locations. The 30% case included nearly all of the sites from the various 20% cases. The study found that the bulk power system could be operated at these wind levels, assuming a high degree of coordination in operations across the eastern power markets, based on hourly production simulations modelling.
- For the New York study with 10% wind capacity penetration, 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 minutes. Hourly ramp increased from 858 MW to 910 MW. All increased needs can be met by existing New York resources and market processes. A 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 standard deviation (σ) increased from 700–800 MW to 859–950 MW. Total system variable cost savings increased from $335 million to $430 million when state-of-the-art forecasting was considered in unit commitment ($10.70/MWh of wind). Perfect forecasting increased savings an additional $25 million (GE Energy, 2005).
- For 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 increased as wind capacity reached 10000 MW up to $0.27/MWh, but then decreased to an actual savings of regulation costs at the 15000 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 decreases 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 be approximately $55/MWh of wind energy (GE Energy, 2008).

5. Wind power impacts on transmission network

This section lists results from studies looking at impacts on grid reinforcements and stability of the grid. Grid reinforcement may be needed to accommodate for larger power flows and maintain stable voltage, and is commonly needed if new generation is installed in weak grids far from load centres. The issue is generally the same, be it modern wind power plant or any other power plant. The grid reinforcement needed for wind power is therefore very dependent on where the wind power plants are located relative to load and grid infrastructure, and one must expect results to vary from country to country.

The grid should be sufficiently strong to cope with electricity infeed from added wind power plants, also during failures that may occur in the network. More detailed simulations of power flows in the transmission grid are needed to confirm this. Steady-state load flow and contingency analyses are performed to confirm the steady-state adequacy and utilisation of the transmission system and to assess if the grid is strong enough to cope with added wind power plants also during significant failures. Dynamic system stability analyses are usually performed at higher penetration levels and if there are stability issues foreseen in the system. The chosen deployment of wind generation (including different wind turbine technologies and wind distributions) can also be evaluated against existing grid code requirements, and different mitigation or participation options can be considered. Wind turbine capabilities are still evolving, and may mitigate some wind power impacts.

5.1 Wind turbine capabilities and possibilities to support the grid

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 data acquisition (SCADA) information.

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. In a U.S. 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 & Hawkins, 2007).

Operation of power systems under the effect of voltage dips in wind power has led to TSOs requiring Fault-Ride-Through (FRT) capability in wind power plants. By the end of 2010, 704 Spanish wind power plants were certified against FRT capability (19.2 GW and approximately 95% of installed capacity). A total of 1 GW wind turbines are excluded due to old manufacturers not operating anymore, small-size turbines, or prototype turbines. Figure 16 shows the number of power losses greater than 100 MW from 2005 to 2010 and the percentage of wind power without FRT. As a result of this technical adaptation, the problem of significant wind generation tripping has been solved, and therefore preventive production curtailments for this reason have not been required since 2008.

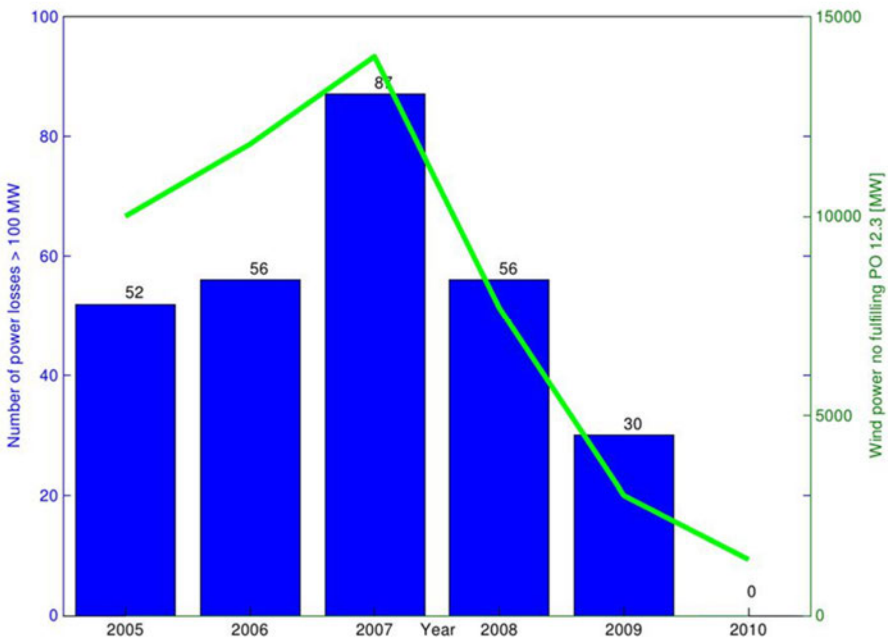


Figure 16. Evolution of wind power with FRT and number of power losses ≥ 100 MW by voltage sags in Spain (Martín-Martínez et al., 2012).

In the case of offshore grids established for the purpose of interconnecting current and future offshore wind power plants, it is necessary to ensure associated components are also beneficial and compliant with onshore grid codes. It is likely that offshore grids will use HVDC lines and converter stations because HVDC technology is more cost-effective than high-voltage alternating current HVAC for long distances. In the Netherlands, while developing control schemes for multi-terminal grids, it has been shown that an approach with multiple "slack buses" allows the most flexible flow of power between countries' loads and offshore power plants. This approach also better accommodates changes to minimize losses and improve security. The performance of such a controlled network has been evaluated for grid codes specified by the German TSO, E.ON Netz, and the Spanish TSO Red Eléctrica. Due to their flexibility and control capabilities, Voltage source controlled high voltage direct current (VSC-HVDC) terminals can comply with the most common TSO requirements, even when sitting inside multi-terminal networks. However, while it is true that VSCs can control their active and reactive power independently, they can only do so within their rated capability. If the reactive power requirements are too strict, they will only be met in detriment of the converter active power and vice-versa. One conclusion is that the impact of the grid code requirements, especially the supply of reactive current during voltage dips, on the operation of a MTDC network during high-wind scenarios can be substantial (Rodrigues et al., 2012).

5.2 Wind turbine impacts on grid stability

A comprehensive set of studies examined the impacts of large, instantaneous penetrations of asynchronous generation (HVDV imports and wind power) on frequency and dynamic stability in Ireland (EirGrid, 2010). During periods with large, instantaneous penetrations of wind power, the studies show the following:

- Network disturbances have the potential to result in a reduction of wind power of greater magnitude than the largest conventional generation infeed, resulting in a significant frequency stability risk.
- Standard islanding protection can result in significant loss of wind power during events when frequency is dropping. Islanding protection on some wind power plants triggers on rate of change of frequency values in excess of +/- 0.5 Hz/second. The reductions in wind power output during these events can result in significant load shedding.
- Critical clearance times are below acceptable levels, resulting in a dynamic stability risk that can be mitigated to a large extent by wind power plant reactive current injection under fault conditions.
- Grid code compliant performance of conventional and wind generation was assumed in the studies. If actual performance is less than this, then actual system risks are greater. Thus, ensuring actual levels of performance are compliant with grid code mandated performance is critical to system security.

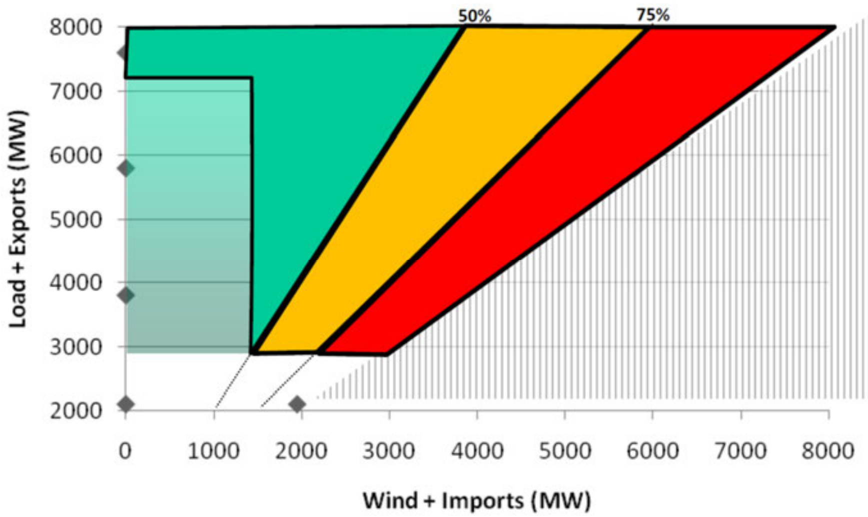


Figure 17. Instantaneous share of wind power production and HVDC imports that can be managed by the Irish power system. The scenarios highlighted in red are the combinations of load, wind power, and HVDC imports/exports that result in instability for which there is no known resolution. The area in orange can be operated in once certain mitigation measures are adopted. The area in green showed no issues. (EirGrid, 2010).

As a result of these studies, a limit on the instantaneous penetration of asynchronous generation of 50% has been adopted. A program of work is underway within EirGrid to implement certain remedial actions identified in the studies and this 50% limit may be increased in the future as these are completed (EirGrid & SONI, 2011). It is not anticipated that instantaneous penetrations above 75% will be possible (Figure 17). Some of the mitigation measures underway include the following:

- Implementation of alternative forms of islanding protection not reliant on rate of change of frequency measurements
- Review of reactive power requirements of wind power plants, particularly requirements for reactive support during disturbances
- Continued development of an online wind stability assessment tool that evaluates dynamic stability for a range of wind power scenarios and identifies a safe upper limit for instantaneous wind power
- On-going review and enforcement of grid code requirements on wind and conventional generation.

5.3 Grid adequacy

Transmission planning for wind is becoming an iterative process consisting of generation expansion planning, economic-based transmission planning, system reliability analysis, and wind integration studies.

The following innovative approaches to transmission expansion for remote wind projects have been undertaken recently in the United States (Smith et al., 2013):

- 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 centres. 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 that was approved consisted of an integrated 345 kV system expansion with over 2000 miles of new lines to accommodate over 18,400 MW of wind capacity California, Colorado, and Minnesota have similar processes underway.
- The Eastern Interconnection of the United States was studied with an annual wind penetration of 20% and 30% in the study year 2024 (EWITS, 2010). New transmission will be required for all the future wind scenarios in the Eastern Interconnection, including the reference case. Without transmission enhancements, substantial curtailment of wind generation would be required for all of the 20% scenarios. Transmission helps reduce the impacts of the variability of the wind, which reduces wind integration costs, increases reliability of the electrical grid, and helps make more efficient use of the available generation resources. Although costs for aggressive expansions of the existing grid are significant, they make up a relatively small piece of the total annualized costs in any of the scenarios studied. In comparing the alternative transmission build-out scenarios, a common “core” of transmission corridors can be identified, indicating that these corridors represent a robust selection of lines that will be useful regardless of the specific wind scenario that will evolve, based on those cases analysed. This study also showed that transmission has an effect on resource adequacy, generally increasing the capacity value of wind plants.
- In the Western United States, WWSIS did not create a detailed transmission plan, but did consider three high renewables scenarios with varying levels of transmission build out: the In-Area scenario met renewables targets within each state and had no interstate transmission; the Mega-Project scenario utilized the best resources, minimizing cost of delivered energy, with significant interstate transmission; and the Local-Priority scenario had an intermediate transmission build out. Notably, WWSIS found very little difference in production cost in these three scenarios, as long as there was significant BA cooperation and intra-hour scheduling (GE Energy, 2010).

In Europe, cross-border transmission is also an issue at the European level:

- In TradeWind project power flows in the European transmission network were simulated with the expected wind power capacity deployment scenarios in 2010, 2015, 2020, reaching 300–400 GW in 2030, a 33% share of the electricity demand covered by wind power in 2030–2040. Increasing wind power capacity in Europe was found to lead to increased cross-border energy exchanges and more severe cross-border transmission bottlenecks in the future, especially with the amounts of wind power capacity in 2020 and 2030. If the 42 identified onshore and offshore cross-border transmission upgrades are implemented, operational costs of power generation would be reduced by 1.5 billion € per year after 2030. TradeWind also evaluated the effect of improved power market rules and quantified these in terms of reduction of the operational costs of power generation. The establishment of intra-day markets for cross-border trade is found to be of key importance for market efficiency in Europe because it will lead to savings in system costs on the order of 1–2 billion € per year as compared to a situation in which cross-border exchange must be scheduled day-ahead. Consequently, the TradeWind analysis concluded that the European electricity market needs intra-day rescheduling of generators and trade, a consolidation of market areas, and increased interconnection capacity in order to enable efficient wind power integration (van Hulle, 2009).
- European Wind Integration Study EWIS: A key recommendation from EWIS is that pan-European modelling, coordinated and adjusted by more precise regional or national models, should be further developed and used, as appropriate, to assess future development of the European transmission network, especially as the proportion of wind generation increases. Looking beyond the immediate measures to strengthen and make best use of existing networks, EWIS also examined the benefits of enhancing cross-border interconnection capacity and identified those links that are likely to have congestion-reducing benefits that exceed the likely capital costs. These include some 30 links with a total capital cost of approximately 12 billion €. It is likely that strengthening these priority cross-border interconnections will give fuel savings and CO_2 emission benefits exceeding the reinforcement capital costs.
- The EU-project SUPWIND assessed transmission infrastructure extension as a mitigation measure for the effects of increased wind generation in power systems. It evaluated the benefits of further line extensions (reinforcements) between Central European (UCTE) and Nordic (NORDEL) countries, and the efficiency gains and the distribution of these gains up to 2030. Results show that reinforcements of 500 MW each in eight existing interconnectors and five new 1 GW lines, costing 8.1 billion € of investment, would bring benefits of 15.5 billion € in 2020. Also, with additional

grid capacity, electricity prices converge to a higher extent compared to a case without investment (Apfelbeck et al., 2009; Kristoffersen et al., 2009).

- The European Network of Transmission System Operators for Electricity (ENTSO-E) (a common body of the European Transmission system operators representing 42 TSOs from 34 countries inside 5 synchronous zones) has started publishing a plan on the next 10 years' grid development every second year, called the Ten-Year-Network-Development-Plan (TYNDP). There are three main reasons for transmission needs: security of supply, connection of renewables, and implementation of the market. Renewables, as one main driver, include a lot of wind power in northern Europe, some hydropower in northern and central Europe, and a lot of solar power expected in southern Europe; 125 GW of new connected renewable energy sources are expected to deliver 38% of the electricity demand (mostly wind and photovoltaic) while CO_2 emissions from the power sector decrease 28–57%. This leads to investments of more than 100 billion € into the grid, which will save 5% of the generating costs by connecting electricity markets. Approximately 51500 km of grid corridors will be built or refurbished through 2020, of which 12300 km direct current DC connections. The kilometres are similar to an increase of 1.3% grid length development despite a major shift in the European generation mix. The costs of more than 100 billion € correspond to 1.5–2 €/MWh over the 10-year period, which is approximately 2% of the bulk power prices or less than 1% of the total end-users' electricity bill (ENTSO-E TYNDP, 2012).

In Europe, another new and international issue is offshore wind power and transmission planning with offshore grids:

- Europe is set to build large amounts of offshore wind power, increasing from 2.5 GW today up to 40–85 GW in the year 2030; some of it will be located far from shore with the need for long subsea power cables to the onshore power system. At the same time, there is a need to better integrate the power markets in Europe by increasing the transnational power exchange capacity. Both developments call for consideration of combining offshore wind power grid connection and interconnections between countries. North Seas Countries Offshore Grid Initiative (NSCOGI) has been formed with the objective of coordinating investigations on technical and grid planning questions, as well as identifying market and regulatory barriers. ENTSO-E has published the assumptions on HVDC technology, which is expected to be available in 2030 (Orths et al., 2012; ENTSO-E, 2011).

- As a result of on-going European research, a new optimization tool for transmission expansion planning has been developed to account for the stochastic properties of wind power distributed over large areas and consider the benefit of transmission capacity between differently priced areas and the value of connecting offshore wind power to the grid versus the investment cost of power cables. The outcome is an optimal grid that answers the question of where to build the new transmission lines/cables and with how much capacity. This tool has been applied to a case study of the North Sea region where there exists extensive plans for both offshore wind development and new subsea interconnectors between countries. In the study, 33 prospective interconnectors were considered and an optimal meshed grid was calculated as a result (Trötscher & Korpås, 2010). In the case study, wind power was modelled using Reanalysis wind velocity data and regional power curves, adapted from the EU project TradeWind.

- The Danish TSO, together with a German university, has developed a benchmark grid investigating operational issues (Rudion et al., 2010 and 2011). They developed an observer-based management system that allows for dynamic slack node allocation in the offshore grid depending on market schedules. The developed algorithm aims at minimum losses while keeping technical limits, such as voltage level, in all nodes.
- The EU project OffshoreGrid calculated the overall infrastructure costs for connecting 126 GW of offshore wind power plants by 2030 in the North Sea by building an offshore grid (de Decker et al., 2011). Total costs would amount to 84–86 billion €, representing about a fifth of the value of the electricity that is generated offshore by 2030. OffshoreGrid assessed 321 current and future offshore wind power plant projects and recommends 114 of them to be clustered in hubs. Doing so would achieve savings up to 14 billion € by 2030, compared to connecting them individually to shore. That is, total investment costs for connecting offshore wind power plants would be 69 billion € rather than 83 billion €. From this hub base case scenario, two possible grid designs were analysed: (1) a direct design, which involves building interconnectors for unconstrained trade between countries first and then tee-in, hub-to-hub, and meshed grid are added with a total cost of 86 billion €, and (2) a split design, which involves building an offshore grid around the planned wind power plants in which the starting point is not only building interconnectors but splitting connection of large wind power plants between countries. These split wind power plant connections establish a path for constrained trade. These offshore wind power plant nodes are then further interconnected to establish an overall meshed design where beneficial. The total cost of this design is approximately 84 billion €. When comparing these two designs in relative terms by looking at the benefit-to-CAPEX (capital-expenditure ratio, the split design is slightly more cost effective than the direct design and yields higher benefit return on investment. Both designs are shown as highly beneficial from a socio-economic perspective because the offshore interconnection capacity in northern Europe is boosted from 8 GW in 2009 to more than 30 GW by 2030. This will also enhance balancing in central Europe by connecting large hydro power capacities in northern Europe. A meshed offshore grid makes the offshore wind power plant connection more reliable and significantly increases security of supply within Europe. The additional cost for creating

a meshed offshore grid, even including wind power plant connections and planned interconnectors, would amount to only 0.1 €c/kWh consumed in the 27 European Union countries (EU27) over the project life time.

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

- In Ireland in 2010, EirGrid launched its network development strategy "GRID 25" (EirGrid, 2010). This is a network investment strategy out to the year 2025 and involves upgrading the transmission system at 110 kV, 220 kV, and 400 kV to accommodate up to 40% energy from renewable generation (approximately 6.6 GW of wind generation capacity) and future conventional generation and demand growth. The total required investment is estimated at 4 billion €. This is the estimated investment that is required to cover the full infrastructure needs of the system and is not due exclusively to wind power. The All Island Grid Study (AIGS, 2008) 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 of wind, total capital investment in transmission in excess of 1,000 million € will be required. This represents a total investment of 154 €/kW of renewable generation installed. The incremental transmission investment required to integrate the 4.3 GW beyond 2.25 GW amounts to 212 €/kW of renewables. When annualised, these costs were modest, adding on the order of 1–2% to the cost of electricity, even in the highest wind portfolios. Significant reactive power issues were identified that were addressed more fully in EirGrid Facilitation of Renewables studies (EirGrid & SONI, 2011), with on-going work (DS3 project, EirGrid & SONI, 2012) including measures to address them.
- In Italy, investments in reinforcement of the transmission grid, in the coming 5 years, have been estimated as more than 2.5 billion € for integration of an additional 6.5 GW of wind power and 11 GW of solar, considering respectively the existing 6.5 GW and 13 GW already installed (2011). (Terna, 2012.)
- The Spanish TSO Red Eléctrica de España (REE), is planning an investment of 8,000 million € during 2007–2016 to accommodate high renewables targets. Power system design and operation has been conducted through different scenarios in 2016. The study was conducted in a summer demand situation with a seasonal non–extreme peak level of 92%. Spain is divided in four zones to study the influence of wind power in the transmission system. Wind power generation is set up to 80% of the installed capacity in the studied area, while the wind power generation in the other three areas is fixed, according to studies of statistical production data. Load flow, short circuit, and stability studies were conducted to study network contingency situations and system recovery after a disturbance (Rodríguez-Bobada et al., 2006). The planned power generation must be capable of providing mainly dynamic voltage control, given the massive penetration of these new technologies. These studies were conducted in peak demand scenarios. Other additional services

are more appropriate to be analysed in low demand situations, such as voltage regulation control and frequency control (REE, 1995; Rodríguez-Bobada et al., 2008). The study concludes that the planned wind power capacity can be integrated into the Spanish power system, highlighting some prerequisites, such as the development of the planned transport network and compliance with the actual and proposed technical grid code requirements. Some significant challenges remain in the areas of dynamic voltage control and management of reserves.

- In Portugal, an effort to allocate the grid reinforcement costs to wind power has been made. The Portuguese TSO has consistently invested in added transmission capacity to integrate the wind production: 145 million € in the period 2004–2009, for increasing wind penetration from 3% to 13%), 159 million € for the 2006–2010 period (16% driven by wind and other smaller independent producers), and 120 million € for the period 2009–2014 (9% of the network investment dedicated to the connection of wind and other comparatively small independent producers) (Smith et al., 2010). The grid reinforcement cost for 5,100 MW of wind power was estimated to be 53 €/kW wind installed, when only accounting for the proportion related to wind power of total cost of each grid development or reinforcement. Adding total costs of all grid development items would mean a grid investment of approximately 100 €/kW of wind (Estanqueiro et al., 2008).
- In Germany, dena study results were approximately 100 €/kW for 36000 MW of wind (Dena, 2005). The recent dena study II (Dena, 2010) calculated the annual cost, including annualised capital as well as operational cost, rather than the investment alone. The result is an annual cost of approximately 20 €/kW/year for 51 GW of wind, together with 18 GW of photovoltaics and 6 GW of biomass generation capacity in 2020 when 39% of the gross electricity consumption is assumed to be contributed by renewable energy sources. Within this scenario, onshore and offshore wind energy installations amount to approximately 49%, or 37 GW, and 18%, or 14 GW, of the total installed renewable energy generation capacities. Apart from the common estimation of the grid extension requirements, different transmission technologies have been evaluated. Investigations of flexible line management (FLM) using line ratings based on actual wind speeds, conductor temperature, and high-temperature conductors to increase the transmission capacity of overhead lines in the extra-high-voltage grid showed that FLM can have a high potential to increase the transmission capacity in some individual cases to overcome grid congestion.
- In the Netherlands, TU Delft and TenneT TSO propose a round-the-year approach by combining market simulations with static security analysis to deal with increased uncertainties (Ciupuliga et al., 2012), as a more accurate alternative to the classic worst-case approach planning. With this method, many combinations of load and generation, including renewable

> energy sources (RES), are created and analyzed, using unit dispatch based on cost optimization, in order to achieve a robust planning under a variety of possible scenarios. The chronological aspect and the correlation of load and wind-speed time series are considered. For each combination, the branch loadings can be determined for normal and contingency situations. Criteria for prioritizing bottlenecks were developed together with a method for ranking them according to a risk-based severity index. It was shown that the new method gives more accurate results, identifying bottlenecks that the snapshot method missed and also giving a reliable bottleneck ranking based on the risk of overload calculation. By analysing the risk of overload and the aggregated severity index, planners can decide whether bottlenecks are severe or if they can be solved (temporarily) via operational measures. The method can be used for comparing the effect of different wind penetration scenarios on the severity indices of different grid elements. The method is currently further developed and targeted to be used in future transmission expansion planning studies of TenneT TSO.

The costs of grid reinforcement needs due to wind power are often not earmarked because it is not straightforward to allocate the cost for investments that benefit all users of the grid. The costs will vary from country to country depending greatly on location of the wind power plants relative to load centres. Grid reinforcement costs are by nature dependent of the existing grid. The grid reinforcement costs are not continuous; there can be single, very-high-cost reinforcements. 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 a 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 a transmission network for the final amount of wind power in the network, instead of having to upgrade transmission lines in several phases.

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. For 99% of the time, the increase is above 15% for all lines, except some very unfavourable cases in which only an increase of 5% is calculated (Lange & Focken, 2008). However, it does not significantly reduce the amount of grid reinforcement needed if all wind-generated power is to be transported at any time (Dena, 2010). The German dena grid study II (Dena, 2010) investigated the cost of a number of different technologies for a major grid extension, since public acceptance of new overhead lines is a major problem. When using conventional overhead lines, three 600-km lines at a cost of 0.9 billion €/year would be needed. If instead an upgrade of existing lines with high-temperature conductors is made, where possible, only one 700-km new line is needed, along with five 700-km line upgrades. The cost would be 1.6 billion €/year. The use of an HVDC meshed grid with underground cables needs three 400-km new cables and costs 2 billion €/year. Using point-to-point connections instead of a meshed grid would further increase the cost. Gas insulated lines were also investigated, but found to be much more expensive than all other options.

Grid reinforcements should be held up against the option of not using all available wind or altering operation of other generation, if grid adequacy is insufficient during only part of the time or for only some production and load situations. A 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 curtail wind power in some situations rather than increase the transmission capability, and coordination of hydropower and wind power in a region with limited export capability can reduce the need for grid upgrade (Matevosyan, 2006; Tande & Uhlen, 2004).

6. Capacity value of wind power

The question of whether there is sufficient capacity at some future date is known as the power or resource adequacy question. This is related to the long-term reserve or planning reserve that power systems carry. To answer questions such as: “Can wind substitute for other generation in the system and to what extent?” and “Is the system capable of meeting a higher (peak) demand if wind power is added to the system?” the capacity value of wind can be calculated. Capacity value is the portion of installed capacity that will provide additional load carrying capability to meet projected increases in system demand. This contribution is typically measured in either MW or as a percentage of installed wind capacity. The term “capacity credit” may also be used.

Two international task force papers (partly including Task 25 collaboration) have recommended the use of loss of load expectation (LOLE) and related methods, such as calculating the Effective Load Carrying Capability (ELCC) to calculate the capacity value of wind (Keane et al., 2011; NERC, 2011).

Wind generation will have a capacity value that is often close to the average power produced by wind power (capacity factor) at low penetrations and will decline as wind penetration increases. In the results summarised in Figure 18, the range is from 40% of installed wind power capacity (in situations with low wind penetration and a high capacity factor at times of peak load), to 5% in higher wind penetrations, or if regional wind power output profiles correlate negatively with the system load profile (a low capacity factor at times of peak load). The aggregation benefits apply to capacity credit calculations – for larger geographical areas, the capacity credit will be higher.

The relative wind capacity credit, as percent of installed wind capacity, is reduced at higher wind penetration, but the extent of this decrease depends on the geographical dispersion of the additional wind plants and the smoothing that results from this dispersion. This is demonstrated by comparing the cases of Mid Norway with one and three wind power plants. In essence, it means that the wind capacity credit for all installed wind in Europe or the United States is likely to be higher than that of the individual countries or regions, with the same penetration level. 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 Figure 18 for capacity value of wind power are from the following studies:

- Germany (Dena, 2005)
- Ireland (AIGS, 2008)
- Norway (Tande & Korpås, 2006)
- Quebec (Bernier & Sennoun, 2010)
- UK (Ilex Energy & Strbac, 2002)
- US Minnesota (EnerNex/WindLogics, 2004 and 2006)
- US New York (GE Energy, 2005)
- US California (Shiu et al., 2006)
- US EWITS study (EWITS, 2010).

The US Eastern Wind Integration Study EWITS did several calculations for capacity value of wind. The study used three scenarios of 20% wind penetration and one scenario of 30% penetration. Three load and wind profile years were used for each scenario. Using the 2004 profile year, the capacity value of wind (Effective Load Carrying Capability ELCC) was 14–18% of wind rated capacity. The 2005 profile results are 14–20%, and the 2006 profile results are 16–23% (EWITS, 2010). The 30% results are 16–19% for profile years 2004–2006, respectively. When a new transmission overlay was added, the results changed significantly, ranging from 24% to 33% of wind rated capacity, depending on penetration.

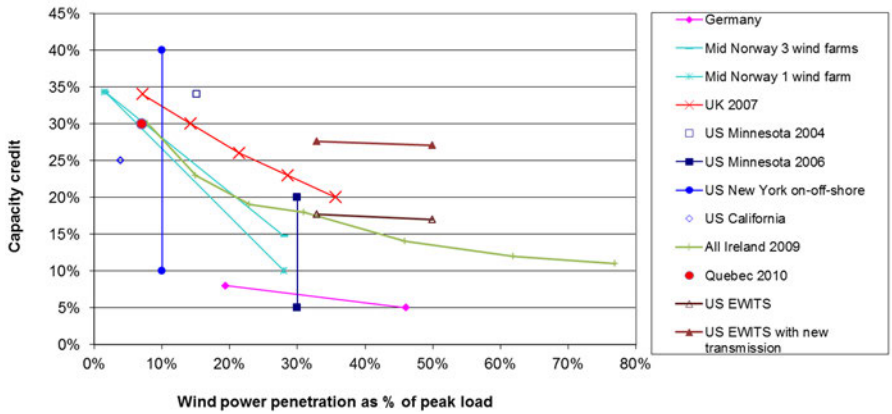


Figure 18. Capacity credit of wind power, results from ten studies, showing reduction of capacity value as penetration level increases. New York on-offshore shows the range of capacity value for wind, when calculated only for onshore sites (10 %) or only offshore sites (40 %).

Results for the capacity credit of wind power in Figure 18 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 the low German capacity credit results shown in Figure 18. For near zero penetration level, all capacity credit values are in the range of the capacity factor of the evaluated wind power plant installations. With correlated wind power and load, the capacity value of wind can be significant, as can be seen in the case of US New York, where onshore wind is generally not high during peak load situations giving capacity value of 10 %, whereas offshore winds tend to blow also at peak load situations giving capacity credit of 40 %.

Hydro Quebec study results show 30% of capacity value for 4% penetration (7.5% of peak load). The study compares two methodologies, the MARS model and the Hydro-Quebec model, that capture the correlation between variation in load and wind generation on an hourly basis. The sensitivity of the results shows that the length of the reference history and the consideration of the effects of very cold temperature on the wind power turbine operation have a direct effect on the precision of such evaluation (Bernier & Sennoun, 2010).

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. This comparison is strongly encouraged so that the trade-offs of using simplified approaches is transparent. Approaches used to calculate capacity credit based on simplified approaches in the United States are summarised in Rogers and Porter (2012).

There are also new, more elaborate methodologies emerging to study capacity credit. For example, the risk assessment methodology in Portugal and Spain calculates not only the general adequacy of the generating system but also the risk associated with the operating reserve (Bessa et al., 2012).

7. Operational practices and technologies that enhance penetration of wind power

Several system operation practices and technologies that mitigate unfavourable impacts and support enhanced penetration can be highlighted based on current wind integration experience and integration study results. The inability to integrate all wind power in the system can be seen as occasional curtailments of wind power that may be needed due to either transmission congestions or insufficient balancing or stability issues in the system. Increasing power system flexibility through increasing 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.

The aggregation benefit of large balancing areas helps in reducing the per-unit variability and forecast errors of wind power and helps by 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 to reduce the forecast errors of wind power that affect operating reserves. Transmission is the key to aggregation benefits, electricity markets, and larger balancing areas. Interconnection will alleviate most instances of curtailment needs in the system, but in the wider interconnected system with higher penetration levels of wind power curtailment, needs will ultimately be decided by conventional plant dispatch limits.

7.1 Operational practices

Experience on coping with high instant wind power shares in the system has been reported in (Söder et al., 2012; Holttinen et al., 2011b; Söder et al., 2007). Denmark is managing the >100% shares occurring approximately 75 hours per year by exporting to neighbouring countries Norway and Sweden. Shares of more than

50% of wind power have been experienced and managed in systems with comparatively small exchange capabilities with their neighbours, i.e., Ireland and the Iberian countries (Portugal and Spain)[1].

In Denmark, the system operator Energinet.dk requires two or three central power stations in both parts of the country to be online, depending on the system conditions. Options for further decrease without compromising system stability are currently being investigated. When there are high wind conditions and low prices, the central power plants are not dispatched by the market and they are currently paid separately to operate. This must-run requirement is primarily related to the safe operation of the HVDC lines and securing sufficient voltage control during power changes on the tie lines. The rule is not specifically related to wind power. To accommodate further increase in wind power, together with expected mothballing of several central power plants, the balancing issues will be tackled by a combination of several different measures (ENTSO-E, 2010). Energinet.dk intends to minimize dependency on must-run units by building the required system support into the grid in the form of new synchronous voltage compensators (SVCs), and taking advantage of the VSC technology on new direct current DC lines.

In Ireland, frequency and voltage stability concerns have necessitated rules for the number of units that remain online (three units in Northern Ireland and five in the Republic of Ireland). The Irish TSO EirGrid may restrict the instantaneous System Non-Synchronous Penetration (SNSP) to 50% of system demand to maintain system security. SNSP is calculated as the sum of asynchronous generation plus the net import over the HVDC interconnectors divided by the system demand. The SNSP limit is imposed for voltage and stability reasons. With the construction of a new, 500 MW interconnection to Great Britain due to be completed in 2012, this may allow wind to meet up to 75% of system demand when the interconnector is exporting (EirGrid & SONI, 2011). Means to change system settings to get to 75% SNSP in 2020 are described in Section 5.2.

Supervising and controlling wind generation in real time can decrease the number and quantity of curtailments, maintaining the quality and security of the electricity supply at the same time as maximizing renewable energy integration. In Spain and Portugal, the TSOs require real-time communication with wind power plants through aggregation and control clusters, enabling the TSO to understand conditions of operation at all times, and to issue the necessary instructions relating to generation. In Spain, the system operator receives the telemetry of 98.6% of the wind generation capacity installed; from which 96% is controllable (the operator is able to adapt its production to the given set-point within 15 minutes). The telecommunication deployment of almost 800 wind power plants spread all around Spain has been achieved as a result of the aggregation of all the distributed resources of more than 10 MW. The information is collected from the production

[1] Portugal and Spain have a good exchange capability, but highly correlated RES generation. Exchange capability towards the rest of the large central European power system is limited due to small interconnection with France.

units, which in turn is needed for real-time operations. Measurements, such as active and reactive power, voltage, connectivity, temperature and wind speed, are taken from wind power plants every 12 seconds.

In Portugal, a wind share close to 75% is controlled through the wind clusters that not only collect data from the most relevant parameters for power system operation, but also have the capability to control the active and reactive power from the wind plants as well as limit extreme power ramps.

Another key aspect about system operation with large amounts of wind power is the grid code or requirements for wind power plants to support the grid. By the end of 2010, 704 Spanish wind power plants were certified for fault-ride-through capability (19258 MW and approximately 95% of the installed capacity). Wind turbines totaling 1,000 MW have been excluded because of their defunct manufacturers, small size, or prototype design. As a result of this technical adaptation, the problem of significant wind generation tripping has been solved – production curtailments for this reason have not been required since 2008 (Söder et al., 2012).

One of the U.S. balancing areas (BAs with the highest penetration of wind is Xcel's Public Service of Colorado, which sees a 12–13% annual average wind penetration and can reach 55–56% on an hourly basis. Public Service of Colorado is pursuing a move to faster inter-changes with neighbouring BAs to help accommodate the wind variability and reduce wind curtailment. Public Service of Colorado's 10% wind integration study showed that using its 300 MW pumped hydro unit to balance net load instead of balancing load (neglecting or separating wind balancing) would reduce its wind integration costs by 26% (Parsons, 2006).

A U.S. study for the Western Interconnection recommended expanding sub hourly dispatch and scheduling, facilitating dynamic transfers between balancing authorities, implementing an energy imbalance market, improving wind forecasting, improving reserves management and demand response, accessing greater flexibility in the dispatch of existing generating plants, and focusing on flexibility for new generating plants as ways to move forward with wind integration at least cost (Western Governors' Association, 2012).

In Japan, many electric utilities have set limits for acceptable wind power installation due to concern for the lack of both downward reserve and frequency regulation, especially at light-load periods at night. Some electric utilities have started to accept the wind power plants that disconnect and give up generating power during light-load periods with less adjustable reserve, and/or wind power plants that employ battery energy storage systems to charge the generated power during the light-load periods. Instead of these uneconomical solutions, demand-side solutions, such as autonomous frequency regulation by electric water heaters (EWHs), has been studied under a simple model of Hokkaido power system in Japan. The result indicates that the acceptable wind power generation increases from 225 MW to 675 MW by applying the proposed autonomous frequency regulation on 170000 electric water heaters, and the total cost to implement the autonomous frequency regulation on the electric water heaters is estimated at less than 1/10 compared with a solution using battery storage (Kondoh, 2010).

7.2 Energy storage

For wind penetration levels of 10–20% of gross demand, the cost effectiveness of electricity storage in power systems is still low (excluding hydropower with large reservoirs or pumped hydro). With higher wind penetration levels, the extra flexibility that storage 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 it is not effective to have dedicated storage for outages in a certain thermal power plant, or to have specific plants following the variation of a certain load.

In current power systems, hydropower reservoirs and pumped hydro are used extensively, as well as heat storage technologies. With annual penetration levels exceeding 15%, pumped hydro storage has been able to reduce curtailments of wind power.

The market operation of storage will be more challenging with wind power. Without wind, or variable renewables, operation is based on load variations and is fairly predictable with higher prices during the day and lower prices at night. However, with high penetrations of wind and other renewables, price differentials are no longer driven by the load but instead are driven by variable renewables participation in the markets through power forecasts. Storage operators will then need to predict when significant forecast errors or uncertainty will occur in order to put forth market offers and to know when to pump and when to generate (Estanqueiro et al., 2012a and b).

In Italy, preliminary activities for the implementation of storage systems for system operator use have started: approximately 250 MW of batteries (up to 1 billion €) installation is foreseen in South of Italy (Estanqueiro et al., 2012b):

- to avoid variable renewable generation curtailment in case of exceeding generation respect to grid transport capacities, by storing the excess of energy in secure conditions to be used later, out of network congestion's periods; and
- to compensate the variable generation by increasing primary and tertiary reserve availability.

In Japan, some electric utilities have started to preferentially accept the wind power plants that install a secondary battery to store the generated power during light-load periods. This is due to the lack of both downward reserve and frequency regulation during light-load periods, mainly caused by a high amount of base-load plants and no flexible exchange of variable wind power via interconnectors between adjacent areas.

In Ireland, studies for a year 2020 scenario have shown that even where there is significant wind curtailment in high wind scenarios, storage was not economically justified until approximately 50% of energy was supplied by wind (Tuohy & O'Malley, 2011). This is due to high capital costs and low round-trip efficiencies, and not considering alternative options such as demand-side management and improved wind forecasts. Merchant storage units participating in energy arbitrage under current market conditions were unprofitable. Opportunities arising from additional benefits of storage, including fast start-up and response times, have yet to be evaluated. For example, due to the significant reserve contribution that can be provided by storage (particularly at times of low load) the system can be operated with less synchronous generation online, although concerns arising from lower system inertia may result.

A common and sensible assumption is that increasing wind penetration in conjunction with PHS will always reduce the CO_2 emissions in a power system. However, the Ireland case study for 2020, while showing an emissions decrease associated with wind power additions, demonstrated that total CO_2 emissions were actually seen to grow with increasing storage capacity due to the increased participation of base-load plants, including coal plants in Great Britain, accessing the Irish system through DC direct current interconnection (Tuohy & O'Malley, 2011; Nyamdash et al., 2010). This emphasises the need to not only examine the emissions impact on the system with the storage facility but also of interconnected systems. The All-island grid study (AIGS, 2008) also showed equal emissions reductions in the UK system to those in Ireland associated with wind additions solely in Ireland.

The value of storage in the power system operation in the United Kingdom was estimated to be 252–970 £/kW (Strbac et al., 2007). For Germany, a 27 million €/year revenue could be foreseen for 400 MW CAES compressed air energy storage (250 million € investment) (FGE/FGH/ISET, 2007). In the Netherlands, international exchange was seen as a more promising alternative to storage in the system (Ummels, 2009).

7.2.1 Hydropower

In several countries, there are plans to increase the pumped hydro capacity (e.g., Portugal to 1.1 GW, Spain to 3 GW) to increase the flexibility of power systems with an increased amount of non-dispatchable renewables (Estanqueiro et al., 2012a and b). In Portugal and Spain, the contribution of pumped hydro storage is already seen in handling excess non-dispatchable generation (see Figure 19 and Figure 20), and reducing (for Spain) the need to curtail part of the available primary wind resource. In 2010, such situations occurred in Spain for approximately 200 hours, with an estimated curtailment of 0.6% of the annual wind resource. In Spain, studies conducted by REE for 2020 forecast a frequency of occurrence of these situations ranging from 400 to 1,400 hours, with a curtailment of 1–6% of the primary renewable resource, taking into account the expected installation of new pumped hydro. Similar studies for Portugal in 2020 show an excess of RES generation totaling 457 GWh, which will represent a curtailment of 65 hours at full power if no storage is assumed (484 hours of partial power). Planned pumped hydro storage for 2020 has the capacity to avoid RES curtailment in 39% of those periods (Estanqueiro et al., 2012).

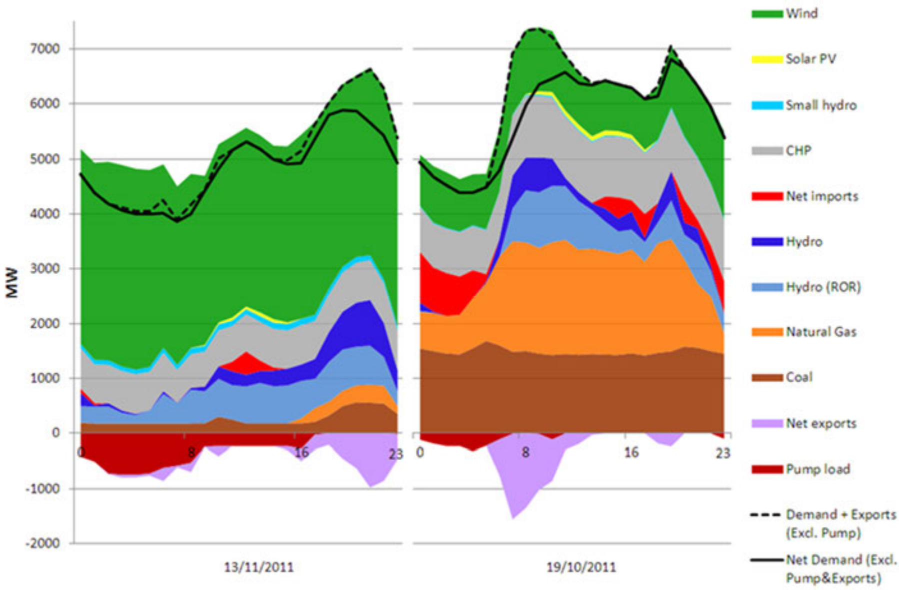


Figure 19. Portuguese load and generation profiles for a high wind day (13.11.2011) (left) and an average wind day (28.10.2011) (right) (Source: www.ren.pt).

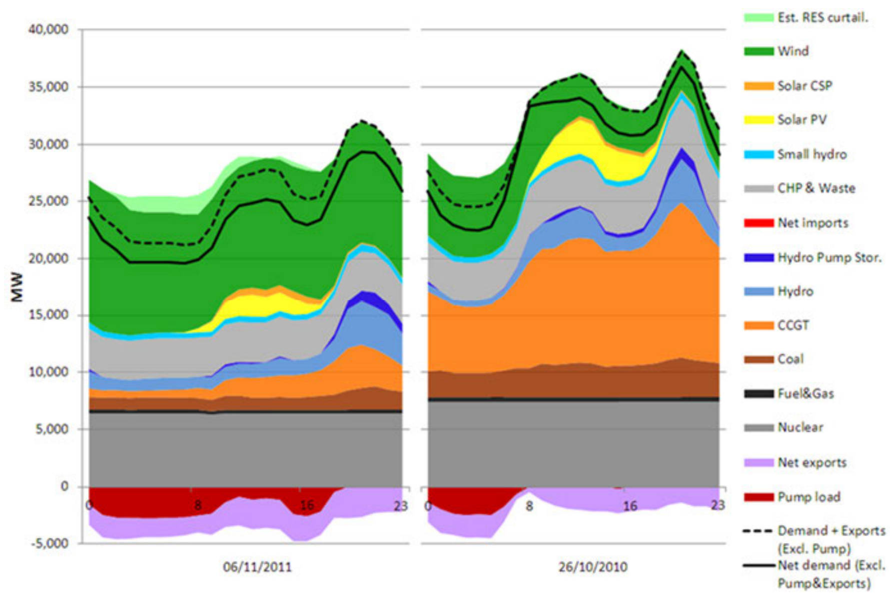


Figure 20. Spanish load and generation profiles for a high wind day (06.11.2011) (left) and an average wind day (26.10.2010) (right) (Source: www.ree.es).

In Ireland and U.S. studies, it was found that energy arbitrage alone does not justify the capital costs involved in large-scale pumped hydro plants. However, ancillary services payments in the future, against a background of increased flexibility requirements from high wind penetrations, may provide an opportunity for storage (Estanqueiro et al., 2012). The Western Wind and Solar Integration Study (WWSIS) examined the operational impact of a new, 100 MW PHS in the Western Interconnection of the United States. If forecasts were perfect, spot prices would generally decrease with increased wind and solar penetration, with a fairly limited spread between high and low spot prices, indicating that there may not be much arbitrage opportunity for storage. In reality, forecasts are imperfect and severe under-forecasts drive spot prices significantly downward, and severe over-forecasts drive spot prices significantly upward, resulting in favourable arbitrage opportunities for storage. However, in order to take advantage of these opportunities, the storage operator needs to know when forecast errors will occur in order to know when to pump and when to generate. In the high renewables case, the PHS earns $3.8 million annually. However, this is still several times less than what is needed to recover costs for a new PHS plant in the United States. (GE Energy, 2010).

In Norway, utilisation of the Norwegian hydro reservoirs due to balancing future North Sea offshore wind have been investigated in Völler & Doorman (2011). The Norwegian reservoir size of approximately 85 TWh is nearly the half of the total installed reservoir size in Europe. The hydro system benefits from higher HVDC capacities because Norway can import more wind energy, especially in periods of low prices in the continent and UK power market. As a result, water can be stored in the reservoirs, so hydropower can be exported in periods of high prices in the continent and UK. Increased transmission capacity couples strongly the Nordic system and the Northern Continental system, therefore making the Nordic system more sensitive to wind penetration from North Sea offshore wind. Reservoir level and production patterns change differently in different scenarios of transmission capacity connecting the Nordic and the Northern Continental systems. For a scenario with moderate HVDC transmission capacity (approximately 2300 MW), the hydropower production follows mainly a distribution with one single maximum of approximately 13 GW. This corresponds well with historical data found at the production peak that is situated between 13 GW and 16 GW. With higher HVDC capacities (approximately 5800 MW), the hydro production probability develops into a double peak pattern due to changed energy flows in the grid. The previous peak of approximately 13 GW now shifts into a double peak at approximately 10 GW and 15 GW (Völler & Doorman, 2011). This illustrates that the hydro system production pattern will move to a more flexible one when needed.

7.2.2 Heat storage

Heat storage can be used in district heating systems for balancing fluctuations in the power system when combining the electricity and heat generation through electric resistance heaters, heat pumps, or combined heat and power (CHP) plants. The stored heat will not be converted back to electricity but will be used as heat in different end uses. A combination of electric resistance heaters and heat storage can be a relatively inexpensive way to deal with low residual demand situations. Heat storage with an electric heater can decrease boiler fuel use more than a standard electric heater could achieve by providing “room” for the excess heat during periods of low power prices (Kiviluoma & Meibom, 2010b).

Heat pumps are rather capital-intensive and therefore require a high amount of full-load hours to be profitable. Fuel-based boilers can be used as a supplement, but the investment cost could be lowered with heat storage. Moreover, during low-heat consumption periods, heat pumps will be forced to operate at low capacity and hence low efficiency. In these situations, heat storage can be used to operate the heat pump intermittently at full capacity.

CHP plants often have operational restrictions due to the need to serve the heat demand. Heat storage can break this bond and, by so doing, liberate the CHP plant to follow power price signals. This will be important during low residual demand situations because CHP units can be shut down or operated at minimum load. Heat storage can also decrease the need for cycling of CHP units, which is likely to increase when the share of variable generation increases.

Kiviluoma and Meibom (2010a, 2010b) evaluated the benefits of heat storage for wind power integration with a generation planning model. All other things being equal, the availability of heat measures (electric resistance heaters, heat pumps, and heat storage) in district heating networks increased the cost-optimal share of wind power considerably (from 35% energy penetration to 47% in the case where no low-cost base load power was available, and from 12% to 15% when low-cost nuclear power was available). In both cases, the heat measures caused a drop in the average cost of electricity by approximately 2.5 €/MWh. The heat demand that was subject to new investments was approximately 27 TWh, whereas the electricity demand was approximately 113 TWh.

Depending on assumptions about the relative price of fuels, CO_2 emissions, and investments, heat storage can strongly reduce CO_2 emissions from the power sector once the additional flexibility enables the power system to replace fossil-fuel-based thermal generation (Kiviluoma & Meibom, 2010a). The main barrier for heat storage is the availability of storage opportunities, besides the competitiveness of electricity for heating, which will improve when fuels get more expensive. Storing hot water in large containers is rather inexpensive and therefore district heating systems or some forms of industrial heat use are prime targets. Heat storage in individual households is less economic, since the smaller containers are more expensive per kWh and the containers will require expensive real estate. Well-insulated houses could also offer some buffer and could be important especially for photovoltaic integration where the generation pattern is typically shorter (daily) than for wind (often a couple of days).

7.3 Electricity markets

There is good experience from Denmark, Spain, Ireland, and New Zealand with balancing wind power variations through forecasting and liquid day-ahead and balancing markets (Ackermann et al., 2009). 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 (the penetration level in the market is much lower, less than 5%) (Holttinen et al., 2009).

Wind integration through markets has many positive impacts. Markets can help managing larger balancing areas, and can pool balancing and flexibility bids. Wind power will also give rise to challenges in electricity markets regarding flexibility, capacity adequacy, and also regarding the participation of wind and solar generators to markets. There are two aspects of flexibility markets: (1) long-term market signals must be sufficient to induce the needed flexibility to be built, and (2) once built, the operational market must provide a sufficient revenue stream to ensure the financial viability of the flexible unit (or load). All of this should be accomplished in an economically efficient manner. The experience with capacity markets appears to be uneven, and this is an evolving area and additional research and/or experimentation is needed (Milligan et al., 2012).

There is already some experience on how wind power impacts the day-ahead electricity market prices. Wind power production will usually be a price taker in the energy markets, bidding at a zero price. Subsidies, such as green certificates paid according to wind power production, can even make it profitable for wind power producers to generate at negative prices. Day-ahead market prices will be lowered during hours of high wind power production, depending on how much wind power will push higher marginal cost generation out of market. During times of low wind generation, the market prices can be higher, resulting in increased price volatility. If the markets respond to increased wind power, by increasing investments in low capital cost / high marginal cost power, the average price can stay the same. However, the experience so far from Denmark, Germany, Spain, and Ireland is that average market prices have decreased due to wind power. Wind forecast errors can mean increased trade in intra-day markets, some hours before delivery, and will impact the real-time/balancing markets in higher penetration levels of wind power. The increased demand in balancing markets usually increases the prices for up/down-regulation more steeply than in electricity markets (Milligan et al., 2012).

In Spain, the impact over the final market price is less than 5%, approximately 1.7–1.8 €/MWh (The National Energy Commission and Spanish Wind Energy Association). A study of the forecasted impact of wind on wholesale electricity prices in Ireland in 2011 (SEAI & EirGrid, 2011) found that the time weighted average wholesale market price was 67 € without wind and 65 € with wind, translating into a reduction in the wholesale market cost of electricity of 74 million €. This cost reduction was almost equal in magnitude to the sum of subsidy costs (50 million €) and increased balancing costs (24 million €), showing that the impact of wind power on the wholesale cost of electricity in Ireland is approximately neutral. The assumed wind capacity in 2011 was 2.2 GW, and the total production from wind was 5.68 TWh.

Wind impacts on market prices can influence wind power producers: in Germany, a March 2012 report from Vattenfall Europe quantified the market value of wind and solar power in Germany with a calibrated market model. Wind power gets 110% of average spot price at a 0% penetration level but only 50% of average spot price at a 0% penetration level (for solar, this is an even sharper decline).

The UVIG Wind Power and Electricity Markets document summarizes the state of market rules and market treatment for wind energy and capacity in major U.S. markets as of the end of October 2011, like scheduling, dispatch frequency, imbalance settlement, and wind forecasting (UVIG, 2011). Some of the major findings are as follows:

- Every ISO/TSO and utility in North America that is integrating a large amount of wind power is using wind plant output forecasts to improve the reliable and economic operation of its system.
- Wind plants are increasingly being allowed to bid in the day-ahead market, and if the marginal unit, to set price.
- Wind generation is increasingly being factored into the economic dispatch process.

In the U.S., more than 60% of the electrical load is managed through energy markets that operate on 5-minute time steps. The Western Interconnection of the United States, less Alberta and California, are evaluating the impact of a proposed Energy Imbalance Market (EIM), which would also operate on a 5-minute time-step to dispatch generation to meet imbalances (King et al., 2011). The Energy Imbalance Market work shows the impact of electrical size on the needed level of reserve needed to integrate wind energy, and calculates the ramp reduction impacts.

Milligan and Kirby (2010) describe some of the characteristics of markets or other institutional structures that can help efficiently integrate wind energy, including the following:

- Large electrical size of balancing area
- Fast (short time-step) energy markets coupled with economic dispatch
- The potential extraction of load-following service from short dispatch intervals
- Inter-regional scheduling characteristics when wind energy is exported – shorter schedule time steps are more efficient for both exporter and importer.

EU-project SUPWIND (Apfelbeck, 2009) investigated impacts of intra-day rescheduling of unit commitment and cross-border exchange on operational costs in the European Power system, for wind energy production by 2015 (8.7% penetration). Four market rules were analysed: (1) day-ahead (12–36 hours ahead) commitment of units with start-up time above 1 hour and power exchange across borders determined with no intra-day rescheduling; (2) unit commitment rescheduled intra-day but power exchanges day-ahead only; (3) unit commitment rescheduling and power exchanges allowed intra-day; and (4) unit commitment rescheduling and power exchange allowed intra-day, plus replacement reserves exchange across border allowed. In total, 31 European countries were modeled (one region per country only) with hourly resolution and one forecast for wind and load in each planning loop. Intra-day rescheduling of unit commitment yields costs savings of 367 million €/year. Allowing rescheduling to be done in cross-border exchanges would increase these operational cost savings to 791 million €/year. Thus, the total system costs savings due to intraday unit commitment rescheduling and cross-border exchange are 1159 million €/year (1% of system costs). Cross-border exchange of reserves did not yield operational cost savings but savings in investment. Cost savings are due to decreased usage of flexible but relatively expensive natural gas and pumped hydro storage power plants when intra-day rescheduling of cross-border exchange is allowed.

EU-project OPTIMATE investigated market designs in Europe and recommends: (1) timing from day-ahead and intra-day markets to shorten the period being auctioned and gate closures as close as delivery time; (2) allowing for complex bids, negative prices, and other features related to dynamic constraints; (3) market integration across borders with implicit (i.e., not separate) auction of transmission capacity; (4) possible reservation of transmission capacity on interconnectors for cross-border balancing; and (5) careful design of the imbalance settlement pricing (OPTIMATE Project, 2011).

The plans in Europe for integrating electricity markets across national borders is expected to facilitate wind energy penetration in addition to reducing volatility of electricity prices. The “EU target model” foresees a “market coupling” that assigns automatically transmission capacity for cross-border trading. The implementation of “continuous intra-day trading” would provide greater flexibility for participants to perform short-term adjustments necessary for integration of greater amounts of variable generation, as opposed to fixed auctions with gate closures at predetermined times like for most day-ahead markets. The design of balancing markets has important implications for wind energy integration. The application of penalties to generators who deviate from their forecast schedules impacts wind producers more than other generators. Balance settlement rules are especially critical in the case of no intra-day market because wind power producers cannot use the more accurate wind forecasts closer to electricity delivery (Pineda & Wilcek, 2012)

8. Conclusions

Adding wind power will bring about a variable and partly unpredictable 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 second term presents a summary of selected, recently concluded studies of wind integration impacts from participating countries. Some quantifiable results are compared, although this is not an easy task due to different methodologies and data used, as well as different assumptions on the interconnection capacity available.

The methodologies regarding increases in operating reserve requirements due to wind power are still evolving, and as larger penetration levels of wind are studied (and managed), there is a trend towards dynamic reserve allocation using probabilistic methods. No new reserve capacity has so far been built, nor has it been foreseen in many studies because the existing power plants can usually manage to provide higher amounts of operating reserves. However, some new pumped hydro schemes are planned in the Iberian peninsula to manage more than 20% wind penetration levels in the future. The summary of results in reserve requirements shows a wide range. The time scale of uncertainty used in the estimates accounts for most differences (sub-hourly variability, 4-hours ahead, or day-ahead time scale of uncertainty).

Estimating the balancing costs of wind power is challenging because capturing and allocating costs are not straightforward. The results for balancing costs for wind show an additional cost of 1 to 5 €/MWh for wind power produced. While it is very difficult to calculate the balancing costs, estimates indicate that these costs are manageable.

The allocation of grid investments to wind power is also challenging, and is rarely done by TSOs, because new infrastructures usually benefit all users and investments are also made for improving electricity markets and increasing the security of the system. There is a trend of more support from wind power plants to the grid, as the requirements in grid codes are evolving.

Wind power has a capacity value in addition to its energy value. There is a recommended methodology for assessing the capacity value of wind power (ELCC) and the value will generally decrease when wind penetration increases. The value will usually increase when looking at larger areas.

There is already significant experience in integrating wind power to power systems. The mitigation of wind power impacts include more flexible operational methods, incentivising flexibility in other generating plants, increasing interconnection to neighbouring regions, and applying demand-side flexibility. Electricity storage is still not as cost effective in larger power systems as other means of flexibility, but it is already seeing initial applications in places with limited transmission. Electricity markets, with cross-border trade of intra-day and balancing resources and emerging ancillary services markets, are seen as promising for future large penetration levels for wind power.

References

Ackermann, T., Kuwahata, R. 2011. Lessons learned from international wind integration studies. Commissioned by Australian Energy Market Operator AEMO. November, 2011. Energynautics GmbH, Germany. http://www.energynautics.com/publications/projects.

Ackermann, T., Ancell, G., Diness Borup, L., Børre Eriksen, P., Ernst, B., Groome, F., Lange, M., Möhrlen, C., Orths, A.G., O'Sullivan, J., de la Torre, M. 2009. Where the Wind Blows. IEEE Power and Energy Magazine, Vol. 7, No. 6, pp. 65–75. DOI: 10.1109/MPE.2009.934268.

AIGS, 2008. All island grid study. http://www.dcenr.gov.ie/Energy/North-South+Co-operation+in+the+Energy+Sector/All+Island+Electricity+Grid+Study.htm.

Amelin, M., Englund, C., Fagerberg, A. 2009. Balancing of wind power in Northern Sweden. Elforsk report 09:88, September 2009.

Apfelbeck, J., Barth, R., Brand, H., Vogel, P., Spiecker, S., Weber, C., Obersteiner, C., Bechrakis, D., Kabouris, J. 2009. Analysis of strategic grid investment and management issues. Nov 2009. SUPWIND Project (Decision Support for Large Scale Integration of Wind Power). http://supwind.risoe.dk/Deliverables/Deliverable%20D6.1.pdf.

Axelsson, U., Murray, R., Neimane, V. 2005. 4000 MW wind power in Sweden – Impact on regulation and reserve requirements. Elforsk Report 05:19, Stockholm. http://www.elforsk.se/Rapporter.

Bernier, L., Sennoun, A. 2010. Evaluating the Capacity Credit of wind generation in Quebec. 9th International workshop on Large-Scale Integration of Wind Power, Quebec, Canada.

Bessa, R.J., Matos, M.A., Costa, I.C., Bremermann, L., Franchin, I., Pestana, R., Machado, N., Waldl, H.-P., Wichmann, C. 2012. Reserve setting and steady-state security assessment using wind power uncertainty forecast: a case study. IEEE Trans. Sustainable Energy, Vol. 3, No. 4, pp. 827–836.

Brandberg, M., Broman, N., Nilsson, M. 2008. Wind Power and Future Trading with Regulating Power. Minerals and Energy Raw Materials Report, Vol. 23, Issue 1, pp. 1–11.

Carlsson, F., 2011. Wind power forecast errors Future volumes and costs. Elforsk report 11:01, May 2011.

Ciupuliga, A.R., Gibescu, M., Pelgrum, E., Jacobs, P.G.H., Jansen, C.P.J., Kling, W.L. 2012. Round-the-year security analysis with bottleneck ranking for interconnected power systems with large-scale wind power. IEEE Transactions on Sustainable Energy, Vol. 3, Issue 1, pp. 85–93.

CRA, 2010. Southwest power pool wind integration study (SPP WITF). Final Report. Charles River Associates. January, 2010. http://www.uwig.org/CRA_SPP_WITF_Wind_Integration_Study_Final_Report.pdf.

Cutululis, N.A., Detlefsen, N., Sørensen, P. 2011. Offshore wind power prediction in critical weather conditions. 10th International Workshop on Large-Scale Integration of Wind Power into Power Systems, 25–26 October 2011, Aarhus, Denmark.

de Decker, J., Kreutzkamp, P. 2011. Offshore electricity grid infrastructure in Europe: A techno-economic assessment. October, 2011. http://www.ewea.org/fileadmin/ewea_documents/documents/publications/reports/Offshore Grid__report.pdf.

DeMeo, E.A., Grant, W., Milligan, M., Schuerger, M.J. 2005. Wind plant integration: costs, status and issues. IEEE Power & Energy Magazine, Vol. 3, Issue 6, pp. 38–46.

Dena, 2005. Planning of the grid integration of wind energy in Germany onshore and offshore up to the year 2020 (Dena Grid study). Deutsche Energie-Agentur Dena, March 2005. English summary and full German version available at: http://www.dena.de/themen/thema-reg/projektarchiv.

Dena, 2010. German Energy Agency (dena): dena Grid Study II – Integration of Renewable Energy Sources in the German Power Supply System from 2015–2020 with an Outlook to 2025 – Summary of the main results by the project steering group. Berlin, Germany.

Dobschinski, J., De Pascalis, E., Wessel, A., von Bremen, L., Lange, B., Rohrig, K., Saint-Drenan, Y.-M. 2010. The potential of advanced shortest-term forecasts and dynamic prediction intervals for reducing the wind power induced reserve requirements. Proceedings of European Wind Energy Conference, EWEC2010, 20–23 April, 2010, Warsaw, Poland.

Doherty, R., O'Malley, M.J. 2005. New approach to quantify reserve demand in systems with significant installed wind capacity. IEEE Transactions on Power Systems, Vol. 20, pp. 587–595.

EirGrid, 2010. Grid 25 – A Strategy for the development of Ireland's electricity grid for a sustainable and competitive future. EirGrid, 2010. http://www.eirgrid.com/media/Grid%2025.pdf.

EirGrid & SONI, 2010. All island TSO facilitation of renewables studies. June, 2010. http://www.eirgrid.com/media/FacilitationRenewablesFinalStudyReport.pdf.

EirGrid & SONI, 2011. Ensuring a secure, reliable and efficient power system in a changing environment. June, 2011. http://www.eirgrid.com/media/Ensuring_a_Secure_Reliable_and_Efficient_Power_System_Report.pdf.

EirGrid & SONI, 2012. DS3: System services consultation – New products and contractual arrangements. June, 2012. http://www.eirgrid.com/media/System_Services_Consultation_Products.pdf.

EnerNex/WindLogics, 2004. Xcel North study (Minnesota Department of Commerce). http://www.uwig.org/XcelMNDOCStudyReport.pdf.

EnerNex/WindLogics, 2006. Minnesota Wind Integration Study Final Report. Vol I, prepared for Minnesota Public Utilities Commission, Nov. 2006. http://www.puc.state.mn.us/portal/groups/public/documents/pdf_files/000664.pdf.

ENTSO-E, 2010. impact of increased amounts of renewable energy on Nordic power system operation. August 31, 2010. https://www.entsoe.eu/fileadmin/user_upload/_library/publications/nordic/operations/20100909_Wind_report.pdf.

ENTSO-E, 2011. Offshore transmission technology report and ENTSO-E views on the offshore grid development in the North Seas. https://www.entsoe.eu/publications/system-development-reports/north-seas-grid-development.

ENTSO-E TYNDP, 2012. Ten-Year-Network-Development-Plan – Package 2012. https://www.entsoe.eu/system-development/tyndp/tyndp-2012.

ERCOT, 2006. Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas. ERCOT System Planning. December, 2006 http://www.ercot.com/content/news/presentations/2006/ATTCH_A_CREZ_Analysis_Report.pdf.

Eriksen, P.B., Ackermann, T., Abildgaard, H., Smith, P., Winter, W., Garcia, J.R. 2005. System operation with high wind penetration. The transmission challenges of Denmark, Germany, Spain and Ireland. IEEE Power & Energy Magazine, Vol. 3, Issue 6, pp. 65–74.

Eriksen, P.B., Orths, A. 2008. Challenges and solutions of increasing from 20 to 50 percent of wind energy coverage in the Danish power system until 2025. Invited keynote paper. Proceedings of the 7th International Workshop on Large Scale Integration; of Wind Power and on Transmission Networks for Offshore Wind Farms, 26–28 May, 2008, Madrid, Spain.

Estanqueiro, A., Castro, R., Flores, P., Ricardo, J., Pinto, M., Rodrigues, R., Lopes, J.P. 2008. How to prepare a power system for 15% wind energy penetration: the Portuguese case study. Wind Energy, Vol. 11, Issue 1, pp. 75–84. DOI: 10.1002/we.253.

Estanqueiro, A., Årdal, A., O'Dwyer, C., Flynn, D., Huertas-Hernando, D., Lew, D., Gómez-Lázaro, E., Ela, E., Revuelta, J., Kiviluoma, J., Rodrigues, L., Amelin, M., Holtinen, H. 2012a. Energy storage for wind integration: Hydropower and other contributions. IEEE PES GM, 22–25 September, 2012, San Diego, CA, USA.

Estanqueiro, A., Årdal, C., O'Dwyer, D., Flynn, D., Huertas-Hernando, D., Lew, E. Gómez-Lázaro, E., Carlini, M., Solvang, E., Ela, E., Kiviluoma, J., Rodrigues, L., Amelin, M. 2012b. Contribution of energy storage for large-scale integration of variable generation. 11th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, WIW12, 13–15 November, 2012, Lisbon, Portugal. Energynautics GmbH.

EWITS, 2010. Eastern Wind Integration and Transmission study. Prepared by EnerNex for the National Renewable Energy Laboratory. January, 2010; revised February, 2011. http://www.nrel.gov/docs/fy11osti/47078.pdf.

Farahmand, H., Doorman, G., Aigner, T., Korpås, M., Huertas-Hernando, D. 2012. Balancing market integration in the Northern European continent: A 2030 case study. IEEE Transactions on Sustainable Energy, October, 2012, Vol. 3, Issue 4, pp. 918–930.

FGE/FGH/ISET, 2007. Bewertung der Optimierungspotenziale zur Integration der Stromerzeugung aus Windenergie in das Übertragungsnetz. http://www.erneuerbare-energien.de/inhalt/42024/4591.

GE Energy, 2005. The effects of integrating wind power on transmission system planning, reliability, and operations. Report on phase 2. Prepared for The New York State Energy Research and Development Authority, City, State, March 2005. http://www.windaction.org/documents/157.

GE Energy, 2008. Analysis of wind generation impact on ERCOT ancillary services requirements. http://www.uwig.org/AttchB-ERCOT_A-S_Study_Final_Report.pdf.

GE Energy, 2010. Western wind and solar integration study: NREL report SR-5500-47434, May, 2010.

Giebel, G., Brownsword, R., Kariniotakis, G., Dernhard, M., Draxl, C. 2011. The state of the art in short-term prediction of wind power: A literature overview. deliverable D-1.2 of Anemos.plus. http://www.prediktor.dk/publ/GGiebelEtAl-StateOfTheArtInShortTermPrediction_ANEMOSplus_2011.pdf.

Gil, A., de la Torre, M., Rivas, R. 2010. Influence of wind energy forecast in deterministic and probabilistic sizing of reserves. 9th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, October, 2010, Quebec, Canada.

Helander, A., Holttinen, H., Paatero, J. 2009. Impact of wind power on the power system imbalances in Finland. IET Renewable Power Generation Journal, Vol. 4, Issue 1, pp. 75–84.

Hodge, B.-M., Lew, D., Milligan, M., Holttinen, H., Sillanpää, S., Gómez-Lázaro, E., Scharff, R., Söder, L., Larsén, X.G., Giebel, G., Flynn, D., Dobschinski, J. 2012. Wind power forecasting error distributions. An international comparison. 11th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, WIW12, 13–15 November, 2012, Lisbon, Portugal, 2012.

Holttinen, H. 2005. Optimal electricity market for wind power. Energy Policy, Vol. 33, Issue 16, pp. 2052–2063

Holttinen, H., Lemström, B., Meibom, P., Binder, H., Orths, A.G., van Hulle, F., Ensslin, C., Hofmann, L., Winter, W., Tuohy, A., O'Malley, M., Smith, P., Pierik, J., Tande, J.O., Estanqueiro, A., Ricardo, J., Gomez, E., Söder, L., Strbac, G., Shakoor, A., Smith, J.C., Parsons, B., Milligan, M., Wan, Y.H. 2007. Design and operation of power systems with large amounts of wind power. State-of-the-art report. VTT Technical Research Centre of Finland, Espoo. VTT Working Papers 82. http://www.vtt.fi/inf/pdf/workingpapers/2007/W82.pdf.

Holttinen, H., Meibom, P., Orths, A., van Hulle, F., Lange, B., O'Malley, M., Pierik, J., Ummels, B., Tande, J.O., Estanqueiro, A., Matos, M., Gomez, E., Söder, L., Strbac, G., Shakoor, A., Ricardo, J., Smith, J.C., Milligan, M., Ela, E. 2009. Design and operation of power systems with large amounts of wind power. VTT Technical Research Centre of Finland, Espoo. VTT Research Notes 2493. http://www.vtt.fi/inf/pdf/tiedotteet/2009/T2493.pdf.

Holttinen, H., Stenberg, A. 2011. Wind power balancing costs for different size actors in the Nordic electricity market. Conference proceedings of the EWEA, 14–17 March, 2011, Brussels, Belgium,

Holttinen, H., Kiviluoma, J., Estanqueiro, A., Gómez-Lázaro, E., Rawn, B., Dobschinski, J., Meibom, P., Lannoye, E., Aigner, T., Wan, Y.H., Milligan, M., 2011a. Variability of load and net load in case of large scale distributed wind power. Proceedings of 10th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Farms, 25–26 October, 2011, Aarhus, Denmark. Pp. 177–182.

Holttinen, H., Orths, A.G., Eriksen, P.B., Hidalgo, J., Estanqueiro, A., Groome, F., Coughlan, Y., Neumann, H., Lange, B., Hulle, F., Dudurych, I. 2011b. Currents of change. IEEE Power & Energy Magazine, Vol. 9, Issue 6, pp. 47–59.

Holttinen, H., Koreneff, G. 2012. Imbalance costs of wind power for a hydro power producer in Finland. Wind Engineering, Vol. 36, Issue 1, pp. 53–68.

Holttinen, H., Milligan, M., Ela, E., Menemenlis, N., Dobschinski, J., Rawn, B., Bessa, R.J., Flynn, D., Gomez Lazaro, E., Detlefsen, N. 2012. Methodologies to determine operating reserves due to increased wind power. IEEE Transactions on Sustainable Energy, Vol. 3, No. 4, pp. 713–723.

van Hulle, F., Tande, J.O., Uhlen, K., Warland, L., Korpås, M., Meibom, P., Sørensen, P., Morthorst, P.E., Cutululis, N., Larsen, H., Woyte, A., Verheij, F., Kleinschmidt, C., Moldovan, N., Holttinen, H., Lemström, B., Uski-Joutsenvuo, S., Gardner, P., Purchala, K., Tiedemann, A., Kreutzkamp, P. 2009. Final Report TradeWind. http://www.trade-wind.eu.

IEA WIND, 2012. IEA WIND 2011 Annual Report. http://www.ieawind.org/annual_reports_PDF/2011.html.

Ilex Energy & Strbac, G. 2002. Quantifying the system costs of additional renewables in 2020. DTI, 2002. http://www.decc.gov.uk/assets/decc/publications/white_paper_03/file21352.pdf.

Jordan, G., Sundar, V. 2012. Analysis of cycling costs in western wind and solar integration study. NREL report SR-5500-54864. June, 2012.

Keane, A., Milligan, M., Dent, C.J., Hasche, B., D'Annunzio, C., Dragoon, K., Holttinen, H., Samaan, N., Söder, L., O'Malley, M. 2011. Capacity value of wind power. IEEE Trans. Power Systems, Vol. 26, No. 2, pp. 564–572.

King, J., Kirby, B., Milligan, M., Beuning, S. 2011. Flexibility reserve reductions from an energy imbalance market with high levels of wind energy in the western interconnection. NREL Report No. TP-5500-52330.

Kirby, B., Milligan, M. 2008. Facilitating wind Development: The importance of electric industry structure. NREL Report No. TP-500-43251.

Kirby, B., Milligan, M. 2009. Capacity requirements to support inter-balancing area wind delivery. NREL Report No. TP-550-46274. http://www.nrel.gov/docs/fy09osti/46274.pdf.

Kiviluoma J., Meibom P., Tuohy A., Troy N., Milligan M., Lange B., Gibescu M., O'Malley M. 2012. Short Term Energy Balancing With Increasing Levels of Wind Energy. IEEE Transactions on Sustainable Energy, Vol. 3, No. 4, pp. 769–776.

Kiviluoma, J., Meibom, P. 2010a. Influence of wind power, plug-in electric vehicles, and heat storages on power system investments. Energy, Vol. 35, No. 3, pp. 1244–1255.

Kiviluoma, J., Meibom, P. 2010b. Flexibility from district heating to decrease wind power integration costs. In: Proc. of the 12th International Symposium on District Heating and Cooling, 5–7 September, 2010, Tallinn, Estonia.

Kondoh, J. 2010. Autonomous frequency regulation by controllable loads to increase acceptable wind power generation. Wind Energy, Vol. 13, No. 6, pp. 529–541.

Kristoffersen, T., Larsen, H.V., Meibom, P., Gøttig, A., Apfelbeck, J., Barth, R., Brand, H. 2009. WP7 Case analysis of operational management of grids. Deliverable D7.1 Report documenting the findings of WP7. October, 2009. http://supwind.risoe.dk/Deliverables/Deliverable%20D7.1.pdf.

Kumar, N., Besuner, P., Lefton, S., Agan, D., Hilleman, D. 2012. Power plant cycling costs. NREL report SR-5500-55433, July, 2012.

Loutan, C., Hawkins, D. (Eds.) 2007. Integration of Renewable Resources November 2007. http://www.uwig.org/CAISOIntRenewablesNov2007.pdf.

Martín-Martínez, S., Gómez-Lázaro, E., Vigueras-Rodríguez, A., Molina-García, A., Milligan, M., Muljadi, E. Participation of wind power plants in the Spanish power system during events (acepted for publication). In: IEEE PES GM, 22–26 July, 2012, San Diego, CA, USA, pp. 1–8.

Matevosyan, J. 2006. Wind power integration in power system with transmission bottlenecks. PhD study, KTH, Sweden. http://www.diva-portal.org/kth/theses/abstract.xsql?dbid=4108.

Meibom, P., Weber, C., Barth, R., Brand, H. 2009. Operational costs induced by fluctuating wind power production in Germany and Scandinavia. IET Renewable Energy Generation, Vol. 3, Issue 1, pp. 75–83.

Milligan, M. 2003. Wind power plants and system operation in the hourly time domain. Proceedings of Windpower 2003 Conference. 18–21 May, 2003, Austin, TX, USA. NREL/CP-500-33955. http://www.nrel.gov/publications.

Milligan, M., Kirby, B. 2010. Market characteristics for efficient integration of variable generation in the western interconnection. NREL Report No. TP-550-48192. http://www.nrel.gov/docs/fy10osti/48192.pdf.

Milligan, M., Ela, E., Hodge, B.-M., Kirby, B., Lew, D., Clark, K., DeCesaro, J., Lynn, K. 2011. Cost-causation and integration cost analysis for variable generation. NREL report NREL/TP-5500-51860. June, 2011. National Renewable Energy Laboratory, Golden, CO, USA. http://www.nrel.gov/docs/fy11osti/51860.pdf.

Milligan, M., Holttinen, H., Söder, L., Clark, C. 2012. Market structures to enable efficient wind and solar power integration. IEEE PES GM, 22–26 July, 2012 San Diego, CA, USA. DOI:10.1109/PESGM.2012.6345591.

Neimane, V., Carlsson, F. 2008. A massive introduction of wind power. Changed market conditions? Elforsk report 08:41. http://www.vindenergi.org/Vindforskrapporter/v_132.pdf.

NERC, 2011. IVGTF 1.2 report. Methods to Model Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning. http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.

NEWIS, 2010. New England Wind Integration Study, December, 2010. http://www.uwig.org/newis_report.pdf.

Nieuwenhout, F., Brand, A. 2011. The impact of wind power on day-ahead electricity prices in the Netherlands. 8th International Conference on the European Energy Market (EEM), 25–27 May, 2011, Zagreb, Croatia. http://www.ecn.nl/docs/library/report/2011/m11111.pdf.

Nyamdash, B., Denny, E., O'Malley, M. 2010. The viability of balancing wind generation with large scale energy storage. Energy Policy, Vol. 38, No. 11, pp. 7200–7208.

O'Malley, M., Flynn, D., Holttinen, H., Outhre, H., van Hulle, F., Bazilian, M., Denny, E., Infield, D., Keane, A., Power, M., Smith, P., Söder, L. 2011. Integration of RE into electric power systems. Ch 8.2.1 of IPCC Special Report on Renewables (SRREN).

OPTIMATE Project (An Open Platform to Test Integration in new MArkeT designs of massive intermittent Energy sources dispersed in several regional power markets). Current designs and expected evolutions of Day-ahead, Intra-day and balancing market/ mechanisms in Europe. May, 2011. http://www.optimate-platform.eu/workplan/download/d22-d331-d332-d32-current-designs-and-expected-evolutions-of-day-ahead-intra-day-and-balancing-market-mechanisms-in-europe.49.html.

Orths, A., Hiorns, A., van Houtert, R., Fisher, L., Fourment, C. 2012. The European North Seas Countries' Offshore Grid Initiative – the Way Forward. In: IEEE PES GM, 22–26 July, 2012, San Diego, CA, USA, pp. 1–8.

Orths, A., Eriksen, P.B. 2009. Europe going renewable – The TSOs' power transmission challenges – Keynote address. Proceedings of the 8th International Workshop on Large Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Farms; 14.–15. October 2009, Bremen, Germany.

Parsons, B., Milligan, M., Smith, J.C., DeMeo, E., Oakleaf, B., Wolf, K., Schuerger, M., Zavadil, R., Ahlstrom, M., Nakafuji, D.Y. 2006. Grid impacts of wind power variability: Recent assessments from a variety of utilities in the united states.

July, 2006. National Renewable Energy Laboratory, NREL/CP-500-39955, Golden, CO, USA. http://www.nrel.gov/docs/fy06osti/39955.pdf.

Pineda, I., Wilcek, P. 2012. Creating the internal energy market in Europe. EWEA. http://www.ewea.org/uploads/tx_err/Internal_energy_market.pdf.

Porter, K. 2007. Intermittency analysis Final report. Kevin Porter and Intermittency Analysis Project Team. July, 2007. http://www.uwig.org/CEC-500-2007-81.pdf.

Portland General Electric & EnerNex, 2011. PGE Wind Integration Study Phase II. September, 2011. http://www.uwig.org/PGE_Study/PGE_Phase%202_Wind_Integration_Report_9-30-11.pdf.

REE, 1995. Criterios generales de protección del sistema eléctrico peninsular español. Red Eléctrica y empresas eléctricas. http://www.ree.es/publicaciones/publicaciones_on_line.asp.

Ribeiro, F. 2012. Impact of wind power in the Portuguese system operation. 11th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, WIW12, 13–15 November, 2012, Lisbon, Portugal. Pp. 205–208.

Rodrigues, S.F., Teixeira Pinto, R., Bauer, P., Pierik, J. 2012. Optimization of social welfare and transmission losses in offshore MTDC networks through multi-objective genetic algorithm. IEEE 7th International Power Electronics and Motion Control Conference (IPEMC) ECCE Asia, 2–5 June, 2012, Harbin, China

Robitaille, A., Kamwa, I., Heniche Oussedik, A., de Montigny, M., Menemenlis, N., Huneault, M., Forcione, A., Mailhot, R., Bourret, J., Bernier, L. 2012. Preliminary impacts of wind power integration in the hydro-quebec system. Wind Engineering, Vol. 36, No. 1, pp. 35–52.

Rodríguez-Bobada, F., Reis Rodriguez, A., Ceña, A., Giraut, E. 2006. Study of wind energy penetration in the Iberian peninsula. In: European Wind Energy Conference. Athens, Greece, 27 February – 2 March, 2006.

Rodríguez-Bobada, F., Ledesma, P., Martínez, S., Coronado, L., Prieto, E. 2008. Simplified wind generator model for transmission system operator planning studies. 7th International Workshop on Large-Scale Integration of

Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Farms. 26–27 May, Madrid, Spain, 2008.

Rogers, J., Porter, K. 2012. Summary of time period-based and other approximation methods for determining the capacity value of wind and solar in the United States: September 2010 – February, 2012. NREL Report No. SR-5500-54338.

Rudion, K., Orths, A., Eriksen, P., Styczynski, Z.A. 2010. Toward a benchmark test system for the offshore grid in the North Sea. Invited Panel Session Paper, PESGM2010-000010. Proceedings of the IEEE PES GM 10, 25–29 July, 2010, Minneapolis, MN, USA.

Rudion, K., Orths, A., Abildgaard, H., Eriksen, P.B., Søgaard, K. 2011. Energy market-driven offshore power system operation. 10th International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, WIW11, 25–26 October, 2011, Århus, Denmark.

SEAI & EirGrid, 2011. Impact of wind generation on wholesale electricity costs in 2011. http://www.seai.ie/Publications/Energy_Modelling_Group/Impact_of_Wind_Generation_on_Wholesale_Elec_Costs/Impact_of_Wind_Generation_on_Wholesale_Electricity_Costs_in_2011.pdf.

Sensfuß, F., Müller, T., Leprich, U., Altrock, M., Sterner, M. 2011. Vorbereitung und Begleitung der Erstellung des Erfahrungsberichtes 2011 gemäß § 65 EEG im Auftrag des Bundesministeriums für Umwelt, Naturschutz und Reaktorsicherheit. Vorhaben IV Instrumentelle und rechtliche Weiterentwicklung im EEG. Endbericht. http://www.bmu.de/files/pdfs/allgemein/application/pdf/eeg_eb_2011_recht_bf.pdf.

Shiu, H., Milligan, M., Kirby, B., Jackson, K. 2006. California renewables portfolio standard renewable generation integration cost analysis. Multi-year analysis results and recommendations. California Energy Commission, PIER Public Interest Energy Research Programme. http://www.energy.ca.gov/2006publications/CEC-500-2006-064/CEC-500-2006-064.PDF.

Smith, J.C., Milligan, M.R., DeMeo, E.A., Parsons, B. 2007. Utility wind integration and operating impact state of the art. IEEE Transactions on Power Systems, Vol. 22, No. 3, pp. 900–908.

Smith, J.C., Osborn, D., Zavadil, R., Lasher, W., Gómez-Lázaro, E., Trötscher, T., Tande, J.O., Korpås, M., van Hulle, F., Estanqueiro, A., Dale, L., Holttinen, H. 2010. Transmission planning for wind energy: status and prospects. 9th International workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, 18–19 October, 2010, Quebec, Canada.

Smith, J.C., Osborn, D., Zavadil, R., Lasher, W., Gómez-Lázaro, E., Estanqueiro, A., Trötscher, T., Tande, J.O., Korpås, M., van Hulle, F., Holttinen, H., Orths, A., Burke, D., O'Malley, M., Dobschinski, J., Rawn, B., Gibescu, M., Dale, L. 2013. Transmission planning for wind energy in the United States and Europe: status and prospects. WIREs Energy and Environment 2013, 2, pp. 1–13. DOI: 10.1002/wene.8.

Söder, L., Hofmann, L., Orths, A., Holttinen, H., Wan, Y.-H., Tuohy, A. 2007. Experience from wind integration in some high penetration. IEEE Transactions on Energy Conversion, Vol. 22, No. 2, pp. 4–12.

Söder, L., Abildgaard, H., Estanqueiro, A., Hamon, C., Holttinen, H., Lannoye, E., Gomez Lazaro, E., O'Malley, M., Zimmermann, U. 2012. Experience and challenges with short term balancing in European systems with large share of wind power. IEEE Transactions on Sustainable Energy, Vol. 3, Issue 4, pp. 853–861.

Strbac, G., Shakoor, A., Black, M., Pudjianto, D., Bopp, T. 2007. Impact of wind generation on the operation and development of the UK electricity systems. Electrical Power Systems Research, Vol. 77, Issue 9, pp. 1143–1238.

Tande, J. O., Uhlen, K. 2004. Cost analysis case study of grid integration of larger wind farms. Wind engineering, Vol. 28, No. 3, pp. 265–273.

Tande, J.O., Korpås, M. 2006. Impact of large scale wind power on system adequacy in a regional hydro-based power system with weak interconnections. Proceedings of Nordic Wind Power Conference NWPC 2006, 22–23 May, 2006, Espoo, Finland.

Terna 2012. National Transmission Plan Edition 2012. Summary available at http://www.terna.it/default/home_en/electric_system/grid_development_plan/grid_development_plan_summary.aspx.

Trötscher, T., Korpås, M. 2011. A framework to determine optimal offshore grid structures for wind power integration and power exchange. Wind Energy, Vol. 14, No. 8, pp. 977–992. DOI:10.1002/we.461.

Tuohy, A., O'Malley, M. 2011. Pumped storage in systems with very high wind penetration. Energy Policy, Vol. 39, No. 4, pp. 1965–1974.

UKERC, 2006. The Costs and impacts of intermittency: An assessment of the evidence on the costs and impacts of intermittent generation on the British electricity network. UK Energy Research Centre.

Ummels, B.C. 2009. Power system operation with large-scale wind power in liberalised environments. Ph.D. thesis, Delft University of Technology, the Netherlands.

UVIG, 2011. Wind power and electricity markets. http://www.uwig.org/windinmarketstableOct2011.pdf.

Western Governers' Association 2012. Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge. http://www.westgov.org/reports/cat_view/95-reports/263-2012.

Völler, S., Doorman, G. 2011. Changes in the utilisation of the Norwegian hydro reservoir by balancing the North Sea offshore wind. Presented at EWEA Offshore 2011.

Zavadil, R.M., King, J. 2008. Final Report: Wind Integration Study for Public Service of Colorado. Addendum. Detailed Analysis of 20% Wind Penetration. Prepared for Xcel Energy by EnerNex. December, 2008. Knoxville, TN, USA. http://www.uwig.org/CRPWindIntegrationStudy.pdf.

Appendix A: National research plans for wind integration in 2012–2014, Task 25 collaboration

Canada: Manitoba Hydro, Hydro-Quebec will participate in the task work. Hydro Quebec will integrate 4000 MW of wind power in its hydro-dominated system by the year 2015 (with 10% penetration from peak load). With a geographically stretched grid that is not synchronous with its neighbours, maintaining the network reliability at the current level under this new operating condition while continuing to efficiently operate the electrical system still presents important challenges. Hydro-Quebec work will have a focus in the integration of wind power uncertainties by performing the following:

- Developing a wind power forecasting system that will cover from real-time operation to the next planning day and more. This will include the uncertainty estimation taking into account imminent meteorological conditions.
- Improving the methodology to define the operating reserves margins, along the horizon of 1–48 hours and more, taking into account the compounded wind and load forecast uncertainty. The operating reserves margins have to be defined for an acceptable level of risk, including allowance for the scheduling of generating unit outages and the energy transactions.
- Making efforts in the future to link and quantify acceptable risk levels for calculating the reserves with their associated costs and revenues from export sales.
- Defining the additional requirements for ancillary services due specifically to the integration of wind power in the electric system: regulating and load-following reserves. To support this activity, a simulation model is developed and run over a full year at 1–5 minutes time steps. The model, developed by the Hydro Quebec research centre IREQ, takes into account security and regulation rules of the transmission system provider.
- Analysing impacts due to integration of other renewable energy sources (solar, electric cars, etc.).
- Continuing modeling and simulating wind power plants for power system studies allowing analysis on possible interactions between series-compensated power system, real HVDC controls, and massive wind power generation.

Current and ongoing work at Manitoba Hydro (up to 800 MW of wind generation in a 5200 MW hydro system) is as follows:

- Operational experience with reserve levels and load following are compared with study results to ensure that the cost of reserves to support wind generation are consistent with study results.

- Perform annual regulating reserves studies to:
    - o identify what is changing in the amount of regulating reserves required over time to meet North American Electric Reliability Corporation (NERC) generation performance standards, and
    - o identify over time what is driving any changes.
- Develop a tool that indicates the amount of reserve available and at what ramp rate it is available.
- Study the impact of wind generation on (external) Locational Marginal Prices (LMP).
- Acquire operational experience to measure the impact on market transactions/mechanisms. Work with industry organizations to develop market rules that are more wind resource friendly, including due consideration of complementary resources (i.e., reservoir hydro).
- Analyze the impact and estimate the net lost opportunity cost of increasing levels of wind generation on Manitoba Hydro's ability to offer ancillary services into the Midwest Independent Transmission System Operator (MISO) market.
- Explore a more sophisticated approach to managing the uncertainty of the wind generation forecasts integrated with the uncertainty in load forecasts using a probabilistic analysis for both day-ahead market requirements and TSO's reliability assessments.
- Assess the need to work with wind forecasting vendors to develop a more accurate day-ahead forecast that can be used for water management.
- Create a tool to monitoring each wind power plant's forecasts along with an operator view / marketer view to advise on current spare capacity and probability distribution in its magnitude based on projected variation in wind output, load, forced outages, etc.

China: The State Grid Energy Research Institute (SGERI) will participate in the task work within the scope of the proposed work plan. SGERI work will focus on grid expansion and flexible generation deployment for the better use of wind power. For the model development, short-time-scale probabilistic production simulation incorporated with wind power model and operation optimization in a power system with high penetration of wind power will be studied:

- For the optimum deployment of energy resources nationwide, SGERI will study the proper grid configuration and grid planning in China. Planning of new flexible generation and its coordination in capacity, distribution, and operation with wind power and other kinds of renewable energy generations will be researched in depth.

- SGERI is developing a probabilistic production simulation model that will mainly consider the uncertainty of wind power. This will include a new algorithm for production simulation that can better describe the variability of wind power.
- SGERI will investigate and research economic and technologic impact on a hybrid alternating current and direct current power system with the rapid growth of wind power in China.
- The operation optimization method developed for enhancing the operational flexibility in a power system with a large amount of wind power has as objective to promote the use of installed wind power. This includes more flexible control of interconnection lines, larger balancing area control, adjustment of unit commitment, economic dispatching under consideration of large-scale wind power, coordination between thermal power, hydropower and wind power, etc.
- SGERI will research the coordination between thermal power, hydropower, and wind power in Northwest China, and build the models of upgraded dispatching pattern for better use of wind power.
- For the better use of wind power, some technologic and managing means have been proposed from sides of generation, grid, and consumption. For example, conjoint exploitation and operation of thermal power and wind power, demand side response, etc., to the reasonable application of these means, SGERI plans to investigate the capability of these means for enhancing the integration of wind power and the corresponding economic and environmental costs.

Denmark: DTU Wind Energy and the TSO Energinet.dk will participate in the Task 25 work. DTU Wind Energy will contribute to the annex with its results and experiences regarding wind power integration achieved from the participation in a number of projects:

- DTU Wind Energy is responsible for the European-wide assessment of the wind integration measures demonstrated in the EU-funded TWENTIES project. Hence, analysis of the European-wide impact of measures such as storm control, virtual power plants, extension of the power capacities in the Norwegian hydropower system, and line monitoring will be input to the annex. Part of the analysis will be based on Wilmar model runs. CorWind, a wind power fluctuation model developed by DTU Wind Energy, will also be used for quantifying the offshore wind power variability.
- DTU Wind Energy is coordinating a large Nordic project looking at the development of novel solutions for future offshore grids. One of the main tasks is to develop the control of wind power clusters connected to VSC HVDC grids delivering ancillary services to the onshore grids.

- Results on advanced control of wind power plants for delivery of ancillary services, with a focus on primary and secondary control, will be shared in the annex as they become available.
- DTU Wind Energy is coordinating a work package on defence and restoration in the EU project iTesla. DTU Wind Energy role will develop models of wind power plants and other renewables.
- DTU Wind Energy will collaborate with VTT in analysis of impacts of wind power on market prices, balancing costs, and unit cycling in the North European power system using the Wilmar model.

Energinet.dk will contribute to the annex through sharing the results of the TSO-task of preparing the Danish power system for 50% wind power penetration by 2025 (50% of domestic consumption delivered by wind). More specifically, the Energinet.dk contributions are foreseen to be in the following areas:

- The challenges of operating a wind-power-dominated power system without conventional power stations on line (how to provide inertia, sufficient short circuit power, and continuous voltage control when power flow changes direction on tie lines and dynamic voltage support during and after faults)
- The capability of wind parks to provide ancillary services
- Methods for planning new transmission lines in power systems with a large wind power share
- Including the heat sector (heat pumps), the transport sector (electric vehicles) and the gas sector (gas production by electricity) into the power system planning with the objective to create additional flexibility, storage, and balancing opportunities – new transmission lines abroad will increase the ability to accommodate more wind
- Reporting from the ENTSO-E collaboration, especially regarding the studies on a future Nord Sea offshore grid
- Reporting from the on-going EU-funded TWENTIES project (storm control of offshore parks) and EcoGridEU (Smart Grid implementation on the Danish island of Bornholm).

Finland: VTT Technical Research Centre is gathering information of all related studies as the operating agent. There will also be work on reviewing the existing studies and methodologies. The following relevant work is being conducted in the national Smart Grids and Energy Markets research programme, Nordic projects OffshoreDC and Icewind, and EU project REServices:

- The variability of wind power in less than an hour time scale and impacts on reserve requirements, especially regarding storm events
- The impact of prediction errors of wind to the Finnish power system

- The impact of wind power on the Nordic energy balance, spot and balancing market prices and adequacy of balancing power, and the impact of flexibility options in the power system
- The value of direct current transmission links in the Baltic/North Sea
- The value of frequency-related ancillary services from wind and solar in the European context.

Germany: Fraunhofer IWES and The Research Centre for Energy Economics will participate in the Task 25 work, and TSO representatives will follow the work. In its new energy strategy, the German government has decided to transform the energy system to be based mainly on renewable energy and to rapidly end the use of nuclear power – the RES electricity target by 2020 is 35% and 80% by 2050. A new energy research program will focus on renewable energies, energy efficiency, energy storage, network technologies, and the integration of renewable energies in the energy system. The modifications of the new Renewable Energy Act will support an improved market integration of wind energy, and the German participants will be able to report their experiences with the new tariff system. Fraunhofer IWES will contribute to the annex with their results and experiences achieved from the participation in a number of projects with national and European funding:

- Simulation of the electricity supply system with a high share of renewable (virtual electricity system)
- Demonstration of renewable virtual power plants (Regenerative model region of Harz)
- Investigation of ways to a 100% renewable electricity system (Renewable power plant 2050)
- Investigation on methods to forecast and control offshore wind power in Germany (RAVE Grid integration)
- In the area of wind power forecasting, new work is planned to improve the forecast, especially in the shorter time range used for intra-day trading and system security; research on probabilistic forecasting is underway as well as spatially resolved forecasts of the wind power generated at each grid node.

Fraunhofer IWES also participates in the EU-funded TWENTIES project: “Transmission system operation with large penetration of Wind and other renewable Electricity sources in Networks by means of innovative Tools and Integrated Energy Solutions.”

The Research Centre for Energy Economics FfE will contribute to the annex with the results of the following projects:

- Wind Energy – Balancing the forecast errors: The effects on the commercialisation of wind power

- Methods of improving the short-term forecast and the feedback on unit commitment and the intraday market (funding requested)
- "DEA: compound of distributed generation facilities": Analysis of the collective control of distributed generation facilities (DEA) and further commercialization of such a "virtual power plant" by electricity trading and system services
- Demand Response – the technical potential of demand shifting in the industrial area.

Ireland: The Electricity Research Centre (ERC) at University College Dublin and Trinity College Dublin will participate in IEA Task 25. The ERC has three major research projects in the 2011–2015 time frame. Science Foundation Ireland, Strategic Research Cluster in Sustainable Electrical Energy Systems (4.6 million €), Programme for Research in Third Level Institutes, Electricity Research Centre: Grid Integration, (2.6 million €) and Electricity Research Centre Industry Funding (2.1 million €). These research projects all have significant research overlay with IEA Task 25, including:

- development of operational and planning tools and techniques, particularly stochastic methods, for the integration of high levels of wind energy;
- design of optimal market mechanisms suitable for systems with high wind penetrations; and
- optimal strategies for utilising ancillary services from wind generation.

These research programs have significant collaboration with other IEA Task 25 participants, including NREL and DTU. National collaborators include the Economic and Social Research Institute, University of Limerick, and National University of Ireland Maynooth. More than 25 industry partners are involved in the research programs and include the Irish System operator EirGrid, ABB, Intel, etc.

Italy: Terna Rete Italia, the company of the Terna Group that deals with the national electricity grid's operation, maintenance, and development, will participate in Task 25 from Italy. The work on which it will be reporting is related to the definition of a set of procedures highlighting the maximum feasible penetration level of wind power at the planning stage and the ways to optimally operate the generation-transmission system with the aim of minimising the occurrences of wind power curtailment. As a consequence of growing wind power penetrations locally, Terna has to face some new constraints (e.g., redeployment of power flow along feeders, possible feeder ampacity violations, impact on voltage), which severely limit the maximum number and size of connectable wind power plants. Adoption of appropriate energy storage systems, together with the introduction of suitable ancillary service markets for promoting user participation to the network regulation, is envisaged to be of crucial importance. In some cases, an important limiting factor to the massive wind power penetration is represented by the inflexibility of the demand and the existing conventional generation, mostly based on fossil fuels that can hardly warrant the additional reserve needs. Starting from the planning stage, clear and transparent procedures are needed to highlight the required reserve, possibly integrated with non-conventional energy storage systems, such as batteries or compressed air energy storage CAES, identifying the amount of the needed reserve and the most appropriate location. These procedures shall aim at minimising the probability of wind curtailment in the most credible foreseen operating conditions. Thereafter, in the operational stage, further procedures have to be defined addressing the needed reserve in relationship with short-term demand and wind forecasts as well as the associated prediction errors; the impact of wind generation on static and dynamic system stability is finally examined. In this work, by applying the above-mentioned procedures, Terna will assess in a realistic high voltage HV system case:

a) mid-long-term analysis:

- the maximum feasible penetration of wind power, quantifying the additional needed reserve in relationship with the wind variability; how the additional reserve can be provided, either through redispatching of conventional generation or the installation of energy storage devices; the contribution to reserve from flexible demand is also examined assuming appropriate market mechanisms in place;
- mitigation of the wind power penetration limiting factors by increasing flexibility options with storage systems: assess the optimal sizing, siting, and managing strategy for grid connected storage systems. Further analyses addressing the estimation of benefits of energy storage in terms of resolution of grid congestions; peak shaving; reliable reserve for the electricity system, primary frequency regulation.
- impact of wind power on the loadability of the transmission network.

b) short-term analysis:

- impact of wind power on the system stability either at the occurrence of faults or high wind generation ramps up/down (*analysis common also to the mid-long-term time horizon*)
- the variability of wind power in less than an hour time scale and impacts on reserve requirements
- impact of prediction errors of wind on generation dispatch and the system performances in terms of frequency errors, voltage deviations from the rated values, and network congestions.

Japan: AIST and Kansai University will participate in Task 25 from Japan. One of the work efforts on which they will report is related to demand-side management. The impact of controlling the power consumption of residential ohmic-heating water heaters and heat pump water heaters, which will be widely installed in Japan, into power system balancing will be evaluated.

Netherlands: TU Delft and ECN will contribute the following to Task 25 activities:

- North Sea Transnational Grid project (TUDelft and ECN):
  - Determine the best solution (modular, flexible, most cost-effective) for a high-capacity transnational offshore grid, connecting future far and large wind power plants in the North Sea
  - Develop and test a multi-terminal converter control strategy
  - Determine the effects of the offshore grid on the national AC alternating current grids: planning and operating rules to ensure security, regulate power exchange correctly, and avoid congestion, as well as the effect of the offshore grid on the stability of national grid
  - Investigate costs, benefits, and policy regulations related to the realisation of the North Sea grid
- Identification of the options for designing an offshore electricity grid and the legal instruments to create such a grid (TUDelft):
  - This includes the legal, technological, and market considerations that coastal states, the EU, and national legislators and policy makers should take into account when planning and weighing the grid design options. The research takes the North Sea area as an example. Four different options will be examined, varying from a national option, to a bilateral option, a bilateral-multilateral option, and finally a multilateral option.
  - An assessment tool will be developed, which will deliver quantitative results for each of the four technical options. These results will be used to adjust the legal framework, thus ensuring an adequate development of a (trans)national offshore grid.
- Grid code requirements and possibilities for ancillary service provision by HVDC-connected wind power plants (including inertia emulation and oscillation damping); one national and one EU-funded project proposal has been submitted.

Norway: SINTEF will participate in the Task 25 work. Planned studies will focus on offshore wind power in the Northern Europe. Among the most relevant topics are the following:

- Impact of offshore wind on power flows and market prices
- Balancing North Sea wind power with Norwegian hydro plants
- Assessment of market solutions
- Investigations of an offshore DCdirect current grid in the North Sea. This includes offshore wind power plants, oil rigs, and transmission to shore.

Studies will be coordinated and built on recent and on-going European and national research projects, including an engagement in the EU-funded TWENTIES project. SINTEF is also responsible for two Centres for Environmental-friendly Research (CEERs) funded by the Norwegian Research Council: NOWITECH (Norwegian Research Centre for Offshore Wind Technology) and CEDREN (Centre for Environmental Design of Renewable Energy).

Portugal: LNEG will coordinate participation in the Task 25 work. FEUP/INESC-Porto, the Technical University of Lisbon/IST, and the TSO REN will continue to contribute to the work. The Portuguese participation in national and European projects in 2012–2014 is centred on the following topics:

- Virtual Renewable Power Plants (VRPP)
    - (LNEG) Correlation of renewable distributed resources, assessment of the excess of renewable energy generation, and need for added energy storage capacity both on large/national and small/local bases (e.g., pumped hydro, vanadium redox batteries (VRB) and plug-in vehicles). Development of VRPP dynamic and stationary models for application in power system stability studies, and local network congestion for the characterization of the VRPP technical and economic benefits.
    - (INESC-Porto/FEUP) Framework and infrastructure to allow offshore wind power plants to perform as a Virtual Wind / Renewable Power Plant, to allow offshore wind power plants connected by HVDC to aid on the onshore AC alternating current grid dynamic support, with control schemes envisioning the provision of frequency control and inertial emulation as well as dumping alternating current AC small-signal oscillations and Fault Ride-through FRT with provision of reactive current (the EU-funded project TWENTIES).
- Storage Systems and Electric Vehicles
    - (LNEG) Cost/benefit analysis of the existing and forecasted energy storage solutions for the Portuguese Power System under scenarios of high (>25%) and very high (>35%) wind energy penetration and comparison to transmission network reinforcement, for the Iberian Peninsula geographical constraints.
    - (INESC-Porto/FEUP) Impact and integration of electric vehicles in the distribution network with wind power (EU project MERGE and National Project REIVE), also concerning balancing and black start procedures and other aspects related to grid dynamic operation and control. Impacts on generation and grid infrastructures planning are also addressed.
    - (LNEG) Assessment of the impact of electric vehicles EVs and domestic distributed generation sources DGS in the local grid power quality. Local characterization of total harmonic distortion THD, flicker, and voltage profiles (project REIVE).

- Markets
    - (LNEG) Address the challenges of using software autonomous agents to help manage the complexity of electricity markets to negotiate the terms of contracts and de-committing of contracts, considering dynamic pricing tariffs to ally into beneficial coalitions – notably coalitions involving end-user customers and to manage portfolios of customers (FCT project ManREM)
- Transmission Tools for Large Wind Integration
    - (INESC-Porto/FEUP) Innovative tools for the future coordinated and stable operation of the pan-European electricity transmission system (EUproject iTESLA) Procedures for service restoration with large-scale wind power in transmission grids
    - (INESC-Porto/FEUP) Installation of flexible AC transmission systems (FACTS) in a transmission network with large wind generation without fault-ride-through FRT capability. Benefits and methodology to optimize the size and location of the FACTS devices.
- Advanced wind power forecasting algorithms
    - (LNEG) Assessment of the spatial and time characteristics of wind power variability in Portugal as well as the smoothing effects present in data from a large number of wind parks using both time and frequency domain techniques. Automatic detection of wind ramps and extreme wind events with drastic impacts on the power system. This includes the EU-project Norsewind (forecasting) and FCT Fluctwind (characteristics of ramps and fluctuations).
    - (INESC-Porto/FEUP) Ramp forecasting techniques, extreme events forecasting, and development of alternative approaches for modelling the uncertainty. The output of the forecasting algorithms will be used in decision-making problems such as unit commitment and wind power bidding in the electricity market.
- Reserves
    - (INESC-Porto/FEUP) Setting the operating reserve in systems with high penetration of wind power. A tool developed in the European Project ANEMOS, plus will be adapted to the requisites and installed operationally at an end-user, and can establish a new management procedure for system operators with a high penetration of wind power.

Spain: UCLM-IER (Universidad de Castilla-La Mancha/Instituto de Investigación de Energías Renovables will participate in the Task 25 work. There will be work on reviewing and collecting information about the Spanish existing studies. On-going national studies at UCLM include the PhD work on wind and renewable energy in the Spanish power system:

- Integration of renewable energy power plants in power systems under the new international standards: development and validation of electrical models for wind and solar resources
- Frequency control in smart grids with large amount of wind power
- Power fluctuations of wind power plants: analysis and regulation.

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 the following:

- Intra-hour balancing of wind power (PhD student Camille Hamon)
- Hydro scheduling with large amounts of wind power (PhD student Yelena Vardanyan)
- Market design for efficient balancing with large amounts of wind power (PhD student Richard Scharff)
- Solar power integration
- Electric vehicles as a balancing resource
- Primary and secondary control issues with multi-terminal HVDC offshore systems with wind power.

UK: The UK Centre for Sustainable Electricity and Distributed Generation (SEDG) will be the focal point of the UK participation in Task 25. Key areas of work that will be included in the Task 25 Phase 3 are as follows:

- Enhancement of methodologies to analyse system operation and development of systems with large-scale penetration of wind considering the need for generation and demand, storage, and the role and value of interconnections.
- Assessment of transmission requirements for integration of large-scale onshore and offshore wind generation.
- Investigation of the interactions between generation reserve allocation and transmission investment.
- Review of the deterministic and probabilistic transmission network security standards in the context of cost-effective integration of wind generation.
- Understanding of the challenges to operate and design hybrid onshore and offshore shore transmission networks in light of the public opposition to onshore transmission.
- Investigation of alternative regulatory approaches that would facilitate anticipatory investment in transmission to enable timely connection of wind generation.

- Evaluation of various transmission pricing approaches and their impact on network and generation investment (conventional and wind).
- Analysis of alternative approaches to incentivising the investment in peaking and flexible plant in systems with significant penetration of wind generation.

USA: NREL (National Renewable Energy Laboratory) will coordinate the U.S. participation in Task 25. It will work on reviewing the methodology/studies made so far in the United States. Specific efforts that will be included in the Task 25 Phase 3 work include the following:

- High wind penetration studies being carried out in the Eastern Interconnection, primarily the follow-up to the Eastern Wind Integration and Transmission Study. The follow-on study, the Eastern Renewable Generation Integration Study, will include a more detailed examination of the impacts of high wind energy penetrations in the East, and will likely include modelling of demand response.
- Extension of the Western Wind and Solar Integration Study into a second phase. The study will employ a 5-minute economic dispatch model, and will examine in detail the impact of cycling of thermal units on integration. In addition, better solar energy data will be employed to better understand the synergies between wind and solar generation.
- Changes to regional market designs to accommodate higher penetrations of variable output renewable resources. One key project is the evaluation of the proposed Energy Imbalance Market in the Western Interconnection, focusing on the impact of alternative market participation scenarios and flexibility reserve deployment.
- The impact of stochastic or other advanced approaches to unit commitment on wind integration in the United States and how some of these approaches could be implemented in energy markets.

EWEA: European Wind Energy Association EWEA will contribute to the work of Task 25 by reviewing relevant integration studies and policies relevant for wind power integration at the European level. Several studies are underway or in preparation to examine the impact of wind power on the power system at the European level and to explore possibilities to enhance the capability of the system to achieve high wind energy penetration levels by improving transmission, interconnection, and market setup. The work is driven by the European target to achieve 20% of its energy production by renewables in 2020. Various stakeholders are exploring specific solutions, at the technical and policy level, for integrating offshore wind power, including the establishment of transnational offshore grids. EWEA will assess the results from these initiatives, where available, as well as from own studies and initiatives, with focus on the following topics:

- System operation at the European level with large amounts of wind power

- The value of new flexibility measures; more specifically, advances in ancillary services delivery through wind generation
- Requirements, standards, and grid codes for connection, balancing, and congestion management of wind generation at the European level
- Upgrade of the transmission system for large amounts of wind power, especially for the case of offshore grids and electricity highways used in international exchange and trade
- Design of efficient electricity markets with large amounts of wind power, including market design for ancillary services.

Series title and number
VTT Technology 75

Title	**Design and operation of power systems with large amounts of wind power** **Final summary report, IEA WIND Task 25, Phase two 2009–2011**
Author(s)	Hannele Holttinen, Juha Kiviluoma, André Robitaille, Nicolaos A. Cutululis, Antje Orths, Frans van Hulle, Ivan Pineda, Bernhard Lange, Mark O'Malley, Jody Dillon, E.M. Carlini, C. Vergine, Junji Kondoh, Madeleine Gibescu, John Olav Tande, Ana Estanqueiro, Emilio Gomez, Lennart Söder, J. Charles Smith, Michael Milligan & Debbie Lew
Abstract	This report provides a summary of the results from recent wind integration studies. The studies address concerns about the impact of wind power's variability and uncertainty on power system reliability and costs as well as grid reinforcement needs. Quantifiable results are presented as summary graphs: results as a MW-increase in reserve requirements, or €/MWh increase in balancing costs, or results for capacity value of wind power. Other results are briefly summarised, together with existing experience on the issues. There is already significant experience in integrating wind power in power systems. The mitigation of wind power impacts include more flexible operational methods, incentivising flexibility in other generating plants, increasing interconnection to neighbouring regions, and application of demand-side flexibility. Electricity storage is still not as cost effective in larger power systems as other means of flexibility, but is already seeing initial applications in places with limited transmission. Electricity markets, with cross-border trade of intra-day and balancing resources and emerging ancillary services markets, are seen as promising for future large penetration levels for wind power.
ISBN, ISSN	ISBN 978-951-38-7910-5 (URL: http://www.vtt.fi/publications/index.jsp) ISSN-L 2242-1211 ISSN 2242-122X (Online)
Date	January 2013
Language	English
Pages	81 p. + app. 13 p.
Keywords	Wind power, wind energy, wind integration, grid integration, reserve requirements, capacity credit, transmission planning
Publisher	VTT Technical Research Centre of Finland P.O. Box 1000, FI-02044 VTT, Finland, Tel. 020 722 111

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

VTT TECHNOLOGY 75 Design and operation of power systems with large amounts of wind...

ISBN 978-951-38-7910-5 (URL: http://www.vtt.fi/publications/index.jsp)
ISSN-L 2242-1211
ISSN 2242-122X (Online)