THE EUROPEAN WIND ENERGY ASSOCIATION

Powering Europe: wind energy and the electricity grid

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Powering Europe:
wind energy and the electricity grid

Main authors (Vols 1-5): Frans Van Hulle (XPwind), Nicolas Fichaux (European Wind Energy Association - EWEA)

Main authors (Vol 6): Anne-Franziska Sinner (Pöyry), Poul Erik Morthorst (Pöyry), Jesper Munksgaard (Pöyry), Sudeshna Ray (Pöyry)

Contributing authors: Christian Kjaer (EWEA), Justin Wilkes (EWEA), Paul Wilczek (EWEA), Glória Rodrigues (EWEA), Athanasia Arapogianni (EWEA)

Revision and editing: Julian Scola (EWEA), Sarah Azau (EWEA), Zoë Casey (EWEA), Jan De Decker and Achim Woyte (3E), EWEA's Large Scale Integration Working Group

Project coordinators: Raffaella Bianchin (EWEA), Sarah Azau (EWEA)

Design: www.megaluna.be

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1 INTRODUCTION: A EUROPEAN VISION

1 INTRODUCTION

In order to achieve EU renewable energy and CO_2 emission reduction targets, significant amounts of wind energy need to be integrated into Europe's electricity system. This report will analyse the technical, economic and regulatory issues that need to be addressed in order to do so through a review of the available literature, and examine how Europe can move towards a more secure energy future through increased wind power production.

The report's main conclusions are that the capacity of the European power systems to absorb significant amounts of wind power is determined more by economics and regulatory frameworks than by technical or practical constraints. Larger scale penetration of wind power faces barriers not because of the wind's variability, but because of inadequate infrastructure and interconnection coupled with electricity markets where competition is neither effective nor fair, with new technologies threatening traditional ways of thinking and doing. Already today, it is generally considered that wind energy can meet up to 20% of electricity demand on a large electricity network without posing any serious technical or practical problems[1].

When wind power penetration levels are low, grid operation will not be affected to any significant extent. Today wind power supplies more than 5% of overall EU electricity demand, but there are large regional and national differences. The control methods and backup

[1] See IEA Task 25 final report on "Design and operation of power systems with large amounts of wind power": http://ieawind.org/AnnexXXV.html

available for dealing with variable demand and supply that are already in place are more than adequate for dealing with wind power supplying up to 20% of electricity demand, depending on the specific system and geographical distribution. For higher penetration levels, changes may be needed in power systems and the way they are operated to accommodate more wind energy.

Experience with wind power in areas of Spain, Denmark, and Germany that have large amounts of wind energy in the system, shows that the question as to whether there is a potential upper limit for renewable penetration into the existing grids will be an economic and regulatory issue, rather than a technical one. For those areas of Europe where wind power development is still in its initial stages, many lessons can be learned from countries with growing experience, as outlined in this report. However, it is important that stakeholders, policy makers and regulators in emerging markets realise that the issues that TSOs in Spain, Denmark and Germany are faced with will not become a problem for them until much larger amounts of wind power are connected to their national grids.

The issues related to wind power and grid integration mentioned in this report are based on a detailed overview of best practices, past experiences, descriptions and references to technical and economic assessments. The report collects and presents detailed facts and results, published in specialised literature, as well as contributions from experts and actors in the sector. The aim is to provide a useful framework for the current debates on integrating wind power into the grid.

2 TURNING THE ENERGY CHALLENGE INTO A COMPETITIVE ADVANTAGE

Europe is importing 54% of its energy (2006), and that share is likely to increase substantially in the next two decades unless a major shift occurs in Europe's supply strategy[2]. Most of Europe's oil comes from the Middle East and the larger share of its gas from just three countries: Russia, Algeria and Norway. The European economy relies on the availability of hydrocarbons at affordable prices. Europe is running out of indigenous fossil fuels at a time when fossil fuel prices are high, as is the volatility of those prices. The combination of high prices and high volatility pressures the energy markets, and increases the risk on energy investments, thus driving up energy prices including electricity prices. The continued economic and social progress of Europe will depend on its ability to decarbonise its energy mix in order to mitigate the risk to the climate, and use its indigenous renewable resources to mitigate the risk to its energy supply.

Without reliable, sustainable, and reasonably priced energy there can be no sustainable long term growth. It is essential that Europe develops its own internal energy resources as far as possible, and that it strongly promotes energy efficiency. Europe has always led the way in renewable energy capacity development, particularly due to the implementation of directives 2001/77/EC and 2009/28/EC for the promotion of the use of renewable energy sources in the European energy mix.

[2] European Commission Communication 'Second Strategic Energy Review: AN EU ENERGY SECURITY AND SOLIDARITY ACTION PLAN' (SEC(2008) 2871).

Europe has a particular competitive advantage in wind power technology. Wind energy is not only able to contribute to securing European energy independence and climate goals in the future, it could also turn a serious energy supply problem into an opportunity for Europe in the form of commercial benefits, technology research, exports and employment.

The fact that the wind power source is free and clean is economically and environmentally significant, but just as crucial is the fact that the cost of electricity from the wind is fixed once the wind farm has been built. This means that the economic future of Europe can be planned on the basis of known, predictable electricity costs derived from an indigenous energy source free of the security, political, economic and environmental disadvantages associated with conventional technologies.

2.1 Wind power and European electricity

Due to its ageing infrastructure and constant demand growth, massive investment in generation plant and grids are required. Over the next 12 years, 360 GW of new electricity capacity – 50% of current EU electricity generating capacity – needs to be built to replace ageing power plants to meet the expected increase in demand[3]. Since energy investments are long-term investments, today's decisions will influence the energy mix for the next decades. The vision presented in this document shows that wind power meets all the requirements of current EU energy policy and simultaneously offers a way forward in an era of higher fuel and carbon prices.

Wind energy technology has made major progress since the industry started taking off in the early 1980s. Thirty years of technological development means that today's wind turbines are a state-of-the-art modern technology: modular and quick to install. At a given site, a single modern wind turbine annually produces 200 times more electricity and at less than half the cost per kWh than its equivalent twenty five years ago. The wind power sector includes some of the world's largest energy companies. Modern wind farms deliver grid support services – for example voltage regulation – like other power plants do. Effective regulatory and policy frameworks have been developed and implemented, and Europe continues to be the world leader in wind energy.

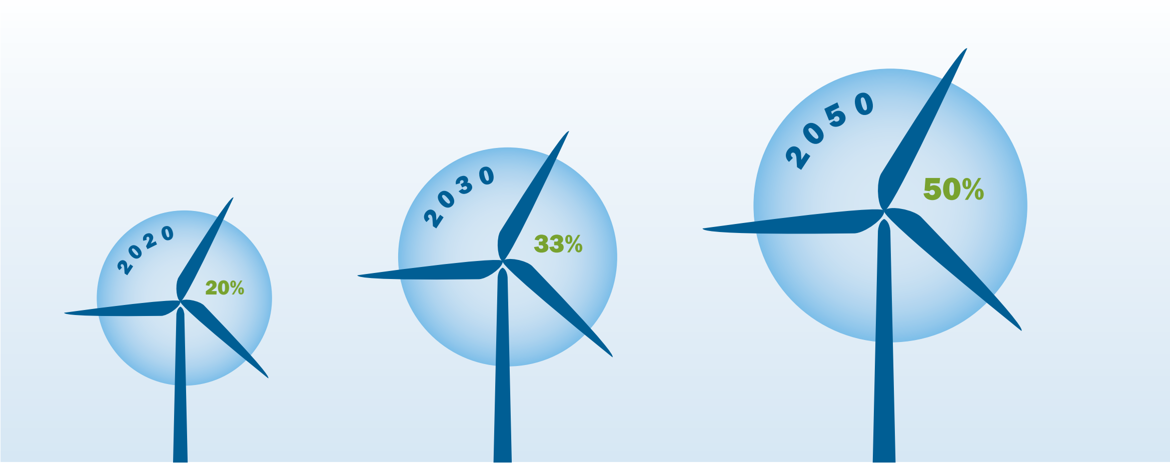
Wind currently provides more than 5% of Europe's electricity[4], but as the cheapest of the renewable electricity technologies, onshore wind will be the largest contributor to meeting the 34% share of renewable electricity needed by 2020 in the EU, as envisaged by the EU's 2009/28 Renewable Energy Directive.

EWEA's "Baseline" scenario for 2020 requires installed capacity to increase from 80 GW today to 230 GW in 2020. Wind energy production would increase from 163 TWh (2009) to 580 TWh (2020) and wind energy's share of total electricity demand would increase from 4.2% in 2009 to 14.2% in 2020. EWEA's "High" scenario requires installed capacity to increase from 80 GW today to 265 GW in 2020. Wind energy production would increase from 163 TWh (2009) to 681 TWh (2020) and wind energy's share of total electricity demand would increase from 4.2% in 2009 to 16.7% in 2020.

On 7 October 2009, the European Commission published its Communication on "Investing in the Development of Low Carbon Technologies[5] (SET-Plan)"stating that wind power would be "capable of contributing up to 20% of EU electricity by 2020 and as much as 33% by 2030" were the industry's needs fully met. EWEA agrees with the Commission's assessment. With

[3] European Commission Communication 'Second Strategic Energy Review: An EU Energy Security and Solidarity Action Plan' (SEC(2008) 2871).
[4] http://www.ewea.org/index.php?id=1665
[5] European Commission (COM(2009) 519 final).

EXPECTED INCREASE IN EU'S SHARE OF ELECTRICITY PROVIDED BY WIND POWER



Source: EWEA

additional research efforts, and crucially, significant progress in building the necessary grid infrastructure over the next ten years, wind energy could meet one fifth of the EU's electricity demand in 2020, one third in 2030, and half by 2050.

Meeting the European Commission's ambitions for wind energy would require meeting EWEA's high scenario of 265 GW of wind power capacity, including 55 GW of offshore wind by 2020. The Commission's 2030 target of 33% of EU power from wind energy can be reached by meeting EWEA's 2030 installed capacity target of 400 GW wind power, 150 GW of which would be offshore. Up to 2050 a total of 600 GW of wind energy capacity would be envisaged, 250 GW would be onshore and 350 GW offshore. Assuming a total electricity demand of 4000 TWh in 2050 this amount of installed wind power could produce about 2000 TWh and hence meet 50% of the EU's electricity demand[6].

In June 2010 the European Commission's Joint Research Centre highlighted that provisional Eurostat data showed that in "2009 about 19.9% (608 TWh) of the total net Electricity Generation (3,042 TWh) came from Renewable Energy sources[7]. Hydro power contributed the largest share with 11.6%, followed by wind with 4.2%, biomass with 3.5% and solar with 0.4%." It went on to conclude "that if the current growth rates of the above-mentioned Renewable Electricity Generation Sources can be maintained, up to 1,600 TWh (45 – 50%) of renewable electricity could be generated in 2020."

Whilst the technology has been proven, the full potential of wind power is still to be tapped. Europe's grid infrastructure was built in the last century with large centralised coal, hydro, nuclear and, more recently, gas fired power plants in mind. The future high penetration levels of wind and other renewable electricity in the power system require decision makers and stakeholders in the electricity sector to work together to make the necessary changes to the grid infrastructure in Europe.

By 2020, most of the EU's renewable electricity will be produced by onshore wind farms. Europe must, however, also use the coming decade to exploit its largest indigenous resource, offshore wind power. For this to happen in the most economical way Europe's electricity grid needs major investments, with a new, modern offshore grid and major grid reinforcements on land. The current legal framework, with newly established

[6] See EWEA's report 'Pure Power: Wind energy targets for 2020 and 2030' on www.ewea.org
[7] Renewable Energy Snapshots 2010. European Commission Joint Research Centre Institute for Energy http://re.jrc.ec.europa.eu/refsys/pdf/FINAL_SNAPSHOTS_EUR_2010.pdf

bodies ENTSO-E and ACER, the key deliverable of the 10-Year Network Development Plan, as well as the ongoing intergovernmental "North Seas Countries' Offshore Grid Initiative" are all steps in the right direction and the political momentum for grid development and the integration of renewable energy is evident.

2.2 Wind power in the system

Wind cannot be analysed in isolation from the other parts of the electricity system, and all systems differ. The size and the inherent flexibility of the power system are crucial for determining whether the system can accommodate a large amount of wind power. The role of a variable power source like wind energy needs to be considered as one aspect of a variable supply and demand in the electricity system.

Grid operators do not have to take action every time an individual consumer changes his or her consumption, for example, when a factory starts operation in the morning. Likewise, they do not have to deal with the output variation of a single wind turbine. It is the net output of all wind turbines on the system or large groups of wind farms that matters. Therefore, wind power has to be considered relatively to the overall demand variability and the variability and intermittency of other power generators.

The variability of the wind energy resource should only be considered in the context of the power system, rather than in the context of an individual wind farm or turbine. The wind does not blow continuously, yet there is little overall impact if the wind stops blowing in one particular place, as it will always be blowing somewhere else. Thus, wind can be harnessed to provide reliable electricity even though the wind is not available 100% of the time at one particular site. In terms of overall power supply it is largely unimportant what happens when the wind stops blowing at a single wind turbine or wind farm site.

2.3 All power sources are fallible

Because the wind resource is variable, this is sometimes used to argue that wind energy *per se* is not reliable. No power station or supply type is totally reliable – all system assets could fail at some point. In fact, large power stations that go off-line do so instantaneously, whether by accident, by nature or by planned shutdowns, causing loss of power and an immediate contingency requirement. For thermal generating plants, the loss due to unplanned outages represents on average 6% of their energy generation. When a fossil or nuclear power plant trips off the system unexpectedly, it happens instantly and with capacities of up to 1,000 MW. Power systems have always had to deal with these sudden output variations as well as variable demand. The procedures put in place to tackle these issues can be applied to deal with variations in wind power production as well, and indeed, they already are used for this in some countries.

By contrast, wind energy does not suddenly trip off the system. Variations in wind energy are smoother, because there are hundreds or thousands of units rather than a few large power stations, making it easier for the system operator to predict and manage changes in supply as they appear within the overall system. The system will not notice when a 2 MW wind turbine shuts down. It will have to respond to the shut-down of a 500 MW coal fired plant or a 1,000 MW nuclear plant instantly.

Wind power is sometimes incorrectly described as an intermittent energy source. This terminology is misleading, because on a power system level, intermittent means starting and stopping at irregular intervals, which wind power does not do. Wind is a technology of variable output. It is sometimes incorrectly expressed that wind energy is inherently unreliable because it is variable.

Electricity systems – supply and demand - are inherently highly variable, and supply and demand are influenced by a large number of planned and unplanned factors. The changing weather makes millions of people switch on and off heating or lighting. Millions of people in Europe switch on and off equipment that demands instant power - lights, TVs, computers. Power stations, equipment and transmission lines break down on an irregular basis, or are affected by extremes of weather such as drought. Trees fall on power lines, or the lines become iced up and cause sudden interruptions of supply. The system operators need to balance out planned and unplanned changes with a constantly changing supply and demand in order to maintain the system's integrity. Variability in electricity is nothing new; it has been a feature of the system since its inception.

Both electricity supply and demand are variable. The issue, therefore, is not the variability or intermittency *per se*, but how to predict, manage and ameliorate variability and what tools can be utilised to improve efficiency. Wind power is variable in output but the variability can be predicted to a great extent. This does not mean that variability has no effect on system operation. It does, especially in systems where wind power meets a large share of the electricity demand.

Photo: Thinkstock

3 MAIN CHALLENGES AND ISSUES OF INTEGRATION

The levels of wind power connected to certain national electricity systems show that wind power can achieve levels of penetration similar to those of conventional power sources without changes to the electricity system in question. In mid 2010, 80 GW of wind power were already installed in Europe, and areas of high, medium and low penetration levels can be studied to see what bottlenecks and challenges occur. Large-scale integration of both onshore and offshore wind creates challenges for the various stakeholders involved throughout the whole process from generation, through transmission and distribution, to power trading and consumers.

In order to integrate wind power successfully, a number of issues have to be addressed in the following areas:

- System design and operation (reserve capacities and balance management, short-term forecasting of wind power, demand-side management, storage, contribution of wind power to system adequacy)
- Grid connection of wind power (grid codes and power quality)
- Network infrastructure issues (congestion management, extensions and reinforcements, specific issues of offshore, interconnection, smart grids)
- Electricity market design issues to facilitate wind power integration (power market rules)

Related to each of these areas are technical and institutional challenges. This report attempts to address both of these dimensions in a balanced way.

Photo: iStock

4 INTEGRATION OF WIND POWER IN EUROPE: THE FACTS

The contribution from wind energy to power generation as foreseen by EWEA for 2020 (meeting 14-17% of the EU's power demand) and 2030 (26-34.7%) is technically and economically possible, and will bring wind power up to the level of, or exceeding, contributions from conventional generation types[8]. These large shares can be realised while maintaining a high degree of system security, and at moderate additional system costs. However the power systems, and their methods of operation, will need to be redesigned to achieve these goals. The constraints of increasing wind power penetration are not linked to the wind energy technology, but are connected to electricity infrastructure cost allocation, regulatory, legal, structural inefficiencies and market changes, and are part of a paradigm shift in power market organisation.

The major issues surrounding wind power integration are related to changed approaches in design and operation of the power system, connection requirements for wind power plants to maintain a stable and reliable supply, and extension and upgrade of the electrical transmission and distribution network infrastructure. Equally, institutional and power market barriers to increased wind power penetration need to be addressed and overcome. Conclusions on these issues, along with recommendations to decision-makers, are presented below.

[8] See EWEA's report 'Pure Power: Wind energy targets for 2020 and 2030' on www.ewea.org

4.1 Wind generation and wind plants: the essentials

State-of-the-art wind power technology with advanced control features is designed to enhance grid performance by providing ancillary services. Using these power plant characteristics to their full potential with a minimum of curtailment of wind power is essential for efficiently integrating high levels of wind power. Advanced grid-friendly wind plants can provide voltage control, active power control and fault-ride-through capability. Emulating system inertia will become possible too. The economic value of these properties in the system should be reflected in the pricing in proportion to their cost.

Wind power provides variable generation with predictable variability that extends over different time scales (seconds, minutes, hours and seasons) relevant for system planning and scheduling. The intra-hour variations are relevant for regulating reserves; the hour by hour variations are relevant for load following reserves. Very fast fluctuations on second to minute scale visible at wind turbine level disappear when aggregated over wind farms and regions. The remaining variability is significantly reduced by aggregating wind power over geographically dispersed sites and large areas. Electricity networks provide the key to reduction of variability by enabling aggregation of wind plant output from dispersed locations. Wind plant control can help control variability on a short time scale.

The latest methods for wind power forecasting help to predict the variations in the time scale relevant for system operation with quantifiable accuracy. Aggregating wind power over large areas and dispersed sites and using combined predictions helps to bring down the wind power forecast error to manageable levels in the time frames relevant for system operation (four to 24 hours ahead). Well interconnected electricity networks have many other advantages. In order to control the possible large incidental forecast errors, reserve scheduling should be carried out in time frames that are as short as possible (short gate-closure times), assisted by real time data on wind power production and site specific wind conditions. The significant economic benefits of improved accuracy justify investment in large meteorological observational networks.

The way grid code requirements in Europe have been developed historically has resulted in gross inefficiencies for manufacturers and developers. Harmonised technical requirements will maximise efficiency for all parties and should be employed wherever possible and appropriate. However, it must be noted that it is not practical to completely harmonise technical requirements straight away. In an extreme case this could lead to the implementation of the most stringent requirements from each Member State. This would not be desirable, economically sound, or efficient.

A specific European wind power connection code should be established within the framework of a binding network code on grid connection, as foreseen in the Third Liberalisation Package. The technical basis for connection requirements should continuously be developed in work carried out jointly between TSOs and the wind power industry.

EWEA proposes a two step harmonisation approach for grid codes: a structural harmonisation followed by a technical harmonisation. The proposed harmonising strategies are urgently needed in view of the significant increase in foreseen wind power penetration and should be of particular benefit to:

- Manufacturers, who will now be required only to develop common hardware and software platforms
- Developers, who will benefit from the reduced costs
- System operators, especially those who have yet to develop their own grid code requirements for wind powered plants

The technical basis for the requirements should be further developed in work carried out jointly between TSOs and the wind power industry. If the proposals can be introduced at European level by means of a concise network code on grid connection, it will set a strong precedent for the rest of the world.

4.2 Power system operations with large amounts of wind power

For power systems to increase their levels of wind penetration, all possible measures to increase flexibility in the system must be considered (flexible generation, demand side response, power exchange through interconnection and energy storage) as well as an appropriate use of the active power control possibilities of wind plants. Wind plant power output control can help manage variability for short amounts of time when it is necessary for system security and when economically justified. For the penetration levels expected up to 2020 there is no economic justification in building alternative large scale storage, although additional storage capacity might be required after 2020.

System operators should make adequate use of short-term wind power forecasting in combination with short gate closure times wherever possible to reduce the need for additional reserve capacity at higher wind power penetration levels. Such reserve capacity will be required to deal with the increased hour ahead uncertainty (load following reserves). Existing conventional plants can often provide this capacity, if they are scheduled and operated in a different way. In addition to using the existing plants – including the slow ramping plants - in a more flexible way, More flexible generation (for example OCGT, CCGT and hydropower) should be favoured when planning the replacement of ageing plants[9] and considering the future generation mix, in order to enable the integration of large-scale variable generation. Providing better access to flexible reserves situated in neighbouring control areas through interconnectors is also a way of improving the system's flexibility.

It is crucial that methods of incorporating wind power forecast uncertainties into existing planning tools and models are developed. The significant economic benefits of improved accuracy justify investment in large wind observation networks. Additional R&D efforts are needed to develop these methods and to improve the meteorological data input for forecasting.

The latest studies indicate that 1-15% of reserve capacity is required at a penetration level of 10%, and 4-18% at a penetration level of 20%. These figures are based on existing examples of high wind power penetration levels (e.g. Spain, Denmark, Germany, Ireland) and a range of system studies (including EWIS), and provide an insight into the additional reserves required for integrating the shares of wind power foreseen for 2020. The large range in the numbers shows that many factors are at play, one of the most important aspects is the efficient use of forecasting tools.

The additional balancing costs at 20% wind power penetration are in the range of €2-4/MWh of wind power, mainly due to increased use of fuel reserves. The available system studies show that there is no steep change in reserve requirements, or on deployment costs, with increasing penetration. An efficient integration of large scale wind power (20% and up) is feasible when the power system is developed gradually in an evolutionary way[10].

Forecasting error can be mitigated by aggregating plants over wider areas. Aggregating wind power over European transmission networks joins up large areas and dispersed sites, and with the help of combined predictions, it can make wind power forecast error manageable for system operation (forecasts made four-24 hours ahead). Efficient integration of wind power implies installing forecasting tools in the control rooms of the system operators. The cost-benefit ratio of applying centralised forecast systems is very high because of the large reductions in the operational costs (balancing) of power generation brought about by reduced uncertainty. Forecasting needs to be customised to optimise the use of the system reserves at various different time scales of system operation. A way forward would be to incorporate wind power prediction uncertainties into existing planning tools and models. Intensive R&D is needed in this area.

Clustering wind farms into virtual power plants increases the controllability of the aggregated wind power for optimal power system operation. Practical examples,

[9] The European Commission says 360 GW of new capacity must be built by 2020 in its Communication 'Second Strategic Energy Review: An EU Energy Security and Solidarity Action Plan' (SEC(2008) 2871).

[10] Evolutionary: gradual development based on the existing system structure.

such as in Spain, demonstrate that operating distributed variable generation sources in a coordinated way improves the management of variability and enhances predictability.

A large geographical spread of wind power on a system should be encouraged through spatial planning, adequate payment mechanisms, and the establishment of the required interconnection infrastructure. This will reduce variability, increase predictability and decrease or remove instances of nearly zero or peak output.

Wind power capacity replaces conventional generation capacity in Europe. The capacity credit of large-scale wind power at European level is in the order of 10% of rated capacity at the wind power penetrations foreseen for 2020. Aggregating wind power from dispersed sites using and improving the interconnected network increases its capacity credit at European level.

A harmonised method for wind power capacity credit assessment in European generation adequacy forecast and planning is required, in order to properly value the contribution of wind power to system adequacy. This method would also constitute a basis for valuating wind power capacity in the future liberalised electricity market.

4.3 Upgrading electricity networks – challenges and solutions

In a scenario with substantial amounts of wind power, the additional costs of wind power (higher installed costs, increased balancing, and network upgrade) could be outweighed by the benefits, depending on the cost of conventional fossil fuels. The expected continuing decrease in wind power generation costs is an important factor. The economic benefits of wind become larger when the social, health and environmental benefits of CO_2 emission reductions are taken into account.

A truly European grid network would also not only overcome the present congestions on some of the main transmission lines but would also bring about savings in balancing and system operation costs and enabling a functioning internal electricity market.

Financing schemes for pan-European transmission grid reinforcements should be developed at EU level, as well as harmonised planning (including spatial planning) and authorisation processes. The revised TEN-E Instrument in the form of a new "EU Energy Security and Infrastructure Instrument" should be better funded and become functional and effective in adding crucial new interconnectors (for more information on TEN-E, see Chapter 4).

With the increased legal separation between generators and network owners/operators, as stipulated in the EU's Third Liberalisation Package (2009/72/EC), the technical requirements which govern the relationship between them must be clearly defined. The introduction of variable renewable generation has often complicated this process significantly, as its generation characteristics differ from the directly-connected synchronous generators used in large conventional power plants.

Upgrading the European network infrastructure at transmission and distribution level is vital for the emerging single electricity market in Europe, and is a fundamental step on the way to the large-scale integration of wind power. Better interconnected networks help aggregating dispersed (uncorrelated) generation leading to continental smoothing, improving the forecasting ability, and increasing the capacity credit of wind power.

For its 2030 wind and transmission scenario (279.6 GW of installed wind capacity), the TradeWind study estimates a yearly reduction of €1,500 million in the total operational costs of power generation as a result of interconnection upgrades. European studies like TradeWind and EWIS have quantified the huge benefits of increasing interconnection capacities for all grid users, and have identified specific transmission corridors to facilitate the implementation of large-scale wind power in Europe.

The costs of upgrading of the European network should be socialised. Grid connection charges should be fair and transparent and competition should be encouraged.

Major national studies in the UK, Germany and Denmark confirm that system integration costs are only a fraction of the actual consumer price of electricity, ranging from €0-4/MWh (consumer level), even under the most conservative assumptions. Integration costs at European level beyond penetration levels of about 25% are not expected to increase steeply. Their value depends on how the underlying system architecture changes over time as the amount of installed wind gradually increases, together with other generating technologies being removed or added to the system.

The main tool for providing a pan-European planning vision for grid infrastructure in line with the long-term EU policy targets should be the regularly updated ten-year network development plan (TYNDP) drafted by the newly established body of European TSOs (ENTSO-E). The TYNDP should reflect the Member States' wind power generation forecasts, as provided in their National Renewable Energy Action Plans, realistically by providing sufficient corridors of adequate capacity. Technologies such as underground HVDC should be used where it can accelerate the implementation.

Accelerated development and standardisation of transmission technology, more specifically multi-terminal HVDC VSC is necessary to avoid unnecessary delays. Neither the proper regulatory conditions, nor any attractive legal incentives for multinational transmission are in place.

Significant barriers to expansion of the network towards a truly pan-European grid exist, including public opposition to new power lines (causing very long lead times), high investment costs and financing needs and the absence of proper cost allocation and recovery methods for transmission lines serving more than just the national interest of a single country.

There is a wide range of short term actions that can optimise the use of the existing infrastructure and transmission corridors. These will help the European transmission system to take up the fast-growing wind power installed capacity, while maintaining high levels of system security. Dynamic line rating and rewiring with high-temperature conductors can significantly increase the available capacity of transmission corridors. A range of power flow technologies (FACTS) and improved operational strategies are suitable immediate options to further optimise the utilisation of the existing network. Some of these measures have already been adopted in the regions of Europe that have large amounts of wind power.

A transnational offshore grid should be constructed to improve the functioning of the Internal Electricity Market and to connect the expected increase in offshore wind energy capacity. Such an offshore grid would require investments in the order of €20 to €30 billion up to 2030.

Such an offshore grid should be built in stages, starting from TSOs' existing plans and gradually moving to a meshed network. Demonstration projects connecting offshore wind farms to two or three countries should be built in the short term to test concepts and develop optimal technical and regulatory solutions. The consequences for the onshore grid in terms of reinforcement in the coastal zones should be considered at an early stage.

The creation of the necessary infrastructure for deploying offshore wind power should be coordinated at European level. The visions developed by EWEA – of 40 GW offshore wind energy capacity in 2020 and 150 GW by 2030 - and backed up by projects like OffshoreGrid[11] should be taken forward and implemented by the European Commission and ENTSO-E. A suitable business model for investing in the onshore and offshore power grids and interconnectors should be rapidly introduced based on a regulated rate of return for investments.

[11] http://www.offshoregrid.eu

With the very high shares of wind power and renewable generation expected in the future, the entire transmission and distribution system has to be designed and operated as an integrated unit, in order to optimally manage more distributed and flexible generation together with a more responsive demand side.

Innovative and effective measures need to be deployed such as 'smart grids', also termed 'active networks', 'intelligent grids' or 'intelligent networks', and assisted with adequate monitoring and control methods to manage high concentrations of variable generation, especially at distribution level. An important research task for the future is to investigate the use of controlled, dynamic loads to contribute to network services such as frequency response.

Proper regulatory frameworks need to be developed to provide attractive legal conditions and incentives to encourage cross-border transmission. This can be helped by building on the experience of "European Coordinators", which were appointed to facilitate the implementation of the most critical identified priority projects within the European TEN-E, particularly where the Coordinator has a clearly defined (and limited) objective.

European energy regulators and ENTSO-E could implement regional committees to ensure regional/transnational infrastructure projects are swiftly completed. Furthermore, the set-up of one central authorising body within a Member State in charge of cross-border projects is worth exploring.

There is a great need for further short-term and long-term R&D in wind energy development at national and European level, in order to develop onshore and offshore technology even more, enable large scale renewable electricity to be integrated into Europe's energy systems and maintain European companies' strong global market position in wind energy technology. An appropriate framework for coordinating the identification of the research needs has been established by the EU's Wind Energy Technology Platform (TPWind). The research needs for the text ten years are presented in the European Wind Initiative, which has a budget of €6 billion, (the Wind Initiative is one of the European Industrial Initiatives which constitute part of the Strategic Energy Technology Plan)[12]. In the field of grid integration, TPWind has set up a dialogue with another Industrial Initiative: the Grid Initiative.

Research priorities for wind integration are:

- Solutions for grid connections between offshore wind farms and HVAC and HVDC grids, and the development of multi-terminal HV DC grids
- Wind plants that can provide system support, and novel control and operating modes such as virtual power plants
- Balancing power systems and market operation in view of design of future power systems with increased flexibility
- Transmission technologies, architecture and operational tools
- More active distribution networks and tools for distributed renewable management and demand-side response
- Tools for probabilistic planning and operation, including load and generation modelling, short-term forecasting of wind power and market tools for balancing and congestion management[13].

4.4 Electricity market design

Imperfect competition and market distortion are barriers to the integration of wind power in Europe. Examples of major imperfections are the threshold to market access for small and distributed wind power generators and the lack of information about spot market prices in neighbouring markets during the allocation of cross-border capacity. In order for a power market to be truly competitive, sufficient transmission capacity is required between the market regions.

The European Commission together with relevant stakeholders (TSOs, regulators, power exchanges, producers, developers and traders) must enforce a

[12] http://ec.europa.eu/energy/technology/set_plan/set_plan_en.htm

[13] Example of such tools can be found in the market model under development in the FP7 project OPTIMATE: http://www.optimate-platform.eu/

comprehensive EU market integration strategy by implementing a target model and roadmap covering forward, day-ahead, intraday and balancing markets as well as capacity calculation and governance issues. Regional Initiatives should converge into a single European market by 2015, as per the European Commission's target[14]. Furthermore, a single central auction office could be established in the EU.

Further market integration and the establishment of intra-day markets for balancing and cross border trade are highly important for integrating large amounts of offshore wind power.

A suitable legal and regulatory framework is required to enable efficient use of the interconnectors between participating countries. The adoption of the Third Liberalisation Package in 2009 should accelerate the much needed reform of EU electricity markets and encourage the take-up of higher amounts of renewables, notably through the clear list of tasks it provides for TSOs and energy regulators. Network codes established in consultation with the market stakeholders should allow wind energy and other variable renewables to be integrated on a level playing field with other forms of generation.

Power systems with wind energy penetration levels of 10-12% of gross electricity demand also need slower power plants (with start-up times above one hour) to participate in the intra-day rescheduling, as well as more flexible plants.

An international exchange of reserves in Europe would bring further advantages. The trade-off between saving money on flexible power plants and sharing of reserves across borders should be investigated with dedicated models.

The ongoing market integration across Europe - notably the establishment of regional markets - is an important building block for a future power system characterised by flexible and dynamic electricity markets, where market participants - including at the level of power demand - respond to price signals, fuel price risk and carbon price risk. Ongoing initiatives at regional level such as the Nordpool market, the Pentalateral Energy Forum, the Irish All-Island market and the Iberian MIBEL are all helping the integration of bigger amounts of variable renewables. The "North Seas Countries' Offshore Grid Initiative" offers a way to create a North Sea market enabling the integration of large amounts of offshore wind power.

Redesigning the market in order to integrate maximum quantities of variable wind power would yield significant macro-economic benefits, through the reduction of the total operational cost of power generation. Intraday rescheduling of generators and application of intra-day wind power forecasting for low reserve requirements results in savings in the order of €250 million per year. The annual savings due to rescheduling power exchange for international trade would be in the order of €1-2 billion[15].

- Transparent and regularly updated information should be available to all market players in order to analyse the best market opportunities. It will not only ensure fairer market behaviour, but also provide for the best possible imbalance management in a market-based and non-discriminatory way.
- Adequate mechanisms for market monitoring should be put in place. Consequently, the authorities must have full access to all relevant information so they can monitor market activities and implement any ex-post investigations and necessary measures to mitigate market power or prevent it potentially being abused.

4.5 The merit order effect of large-scale wind integration

When there is a lot of wind power on the system, electricity wholesale market prices go down due to the so-called merit order effect (MOE). Results from power market modelling show that with the expected wind

[14] See for example: EU Commissioner for Energy Oettinger's speech in March 2010: 'An integrated and competitive electricity market: a stepping stone to a sustainable future' (SPEECH/10/102).

[15] See the TradeWind project report: 'Integrating Wind: Developing Europe's power market for the large-scale integration of wind power' (www.trade-wind.eu).

power capacity reaching 265 GW in 2020, the MOE would amount to €11/MWh, reducing the average wholesale power price level from €85.8/MWh to €75/MWh. The total savings due to the MOE has been estimated at €41.7 billion/year in 2020. The merit order effect will be further influenced by fuel and carbon prices[16].

However, this figure assumes a fully functioning market. It also includes the long-term investments forecast and is therefore based on the long-term market equilibrium. Simulated generation volumes in 2020 require economic feasibility with regards to long run marginal costs. Wind capacity replaces the least cost efficient conventional capacities so that the system is in equilibrium. This shift in the technology mix is the main reason for the observed merit order effect.

In reality this might not always happen. Power market bids are based on short run marginal costs, plants that are not cost efficient might be needed in extreme situations, for example when there is a lot of wind power on the system. The short-term effects of wind power are mostly related to the variability of wind power. The responding price volatility due to increased wind power stresses the cost efficiency of wind power generation. And in the real world, this would lead to a smaller merit order effect than analysed in the future optimal market equilibrium.

Consequently, the results of the study have to be considered carefully, especially considering the assumed future capacity mix, which includes a lot of uncertainties. Moreover, results should not be directly compared to recent literature, which usually estimate the short term price effects of wind power. Here the market is not always in equilibrium and actual price differences and the merit order effect might therefore be very different.

Moreover, the study estimates the volume merit order effect referring to the total savings brought about due to wind power penetration during a particular year. Assuming that the entire power demand is purchased at the marginal cost of production, the overall volume of the MOE has been calculated at €41.7 billion/year in 2020. But this should not be seen as a purely socio-economic benefit. A certain volume of this is redistributed from producer to consumer because decreased prices mean less income for power producers. Currently, only the long-term marginal generation which is replaced by wind has a real economic benefit, and this should be contrasted to the public support for extended wind power generation.

The sensitivity analysis resulted in an increase of the merit order effect by €1.9/MWh when fossil fuel prices (gas, coal and oil) are increased by 25%. In the High fuel price case, wind power makes the power price drop from €87.7/MWh in the Reference scenario to €75/MWh in the Wind scenario. Comparing the resulting merit order effect in the High fuel case of €12.7/MWh to the Base case results of €10.8/MWh, the 25% higher fuel price case gives a merit order effect that is 17.5% higher.

The study showed that fuel prices have a major influence on power prices and marginal cost levels. The merit order effect has been mostly explained by the difference in the technology capacity and generation mix in the various scenarios, especially the differences in the development and utilisation of coal and gas power technologies. Investigating fuel price differences is therefore highly relevant. However, even stronger impacts on the merit order effect might be observed by changing the relative price differences of gas and coal price levels.

The study proved that carbon market assumptions and especially the resulting carbon price level will be a very important variable for the future power market and its price levels. Regarding the sensitivity of the assumed GHG emissions reduction target, the analysis illustrated higher equilibrium prices for the 30% reduction case than for the 20% reduction base case.

However, the results of the sensitivity analysis do very much depend on the assumptions for future abatement potential and costs in all EU ETS sectors, as well as in the industrial sectors.

[16] See Chapter 6 of this report for more information.

Photo: Vestas

5 ROLES AND RESPONSIBILITIES

Wind power is capable of supplying a share of European electricity demand comparable to, or exceeding, the levels currently being met by conventional technologies such as fossil fuels, nuclear and large hydro power. Such penetration levels, however, would require cooperation among decision makers and stakeholders in the electricity sector in order to make the necessary changes to the European grid infrastructure, which was developed with traditional centralised power in mind. Stakeholders in this process should include:

- Wind energy sector: wind turbine and component manufacturers, project developers, wind farm operators, engineering and consulting companies, R&D institutes and national associations
- Power sector: transmission and distribution system operators and owners, power producers, energy suppliers, power engineering companies, R&D institutes, sector associations
- National and European energy regulation authorities
- Public authorities and bodies: energy agencies, ministries, national and regional authorities, European institutions, the Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E)
- Users: industrial and private electricity consumers, energy service providers

TABLE 1: ROLES AND RESPONSIBILITIES

		Stakeholders				
		Wind industry	TSOs and power sector	EU and national energy regulators	EU and national govern-ments	Traders, market operators, users
System design and operation	Introduce increased flexibility as a major design principle (flexible generation, demand side management, interconnections, storage etc.). In addition to using the existing plants – including the slow base load plants - in a more flexible way with increasing penetration, flexible generation (for example OCGT, CCGT and hydropower) should be favoured when planning the replacement of ageing plants and considering the future generation mix, in order to enable the integration of large-scale variable generation. Providing better access to flexible reserves situated in neighbouring control areas through power exchange should be encouraged as a way of improving the system's flexibility.		✓	✓	✓	✓
	Use short-term wind power forecasting in combination with short gate-closure times wherever possible to reduce the need for extra reserve capacity at higher wind power penetration levels. Install forecasting tools in the control room of system operators. In order to control any major incidental forecast errors, reserve scheduling should be done in timeframes that are as short as possible (short gate-closure times), assisted by real-time data on wind power production and site specific wind conditions.	✓	✓	✓		✓
	Develop ways of incorporating wind power uncertainties into existing planning tools and models. Deploy large wind observation networks.	✓	✓			
	Develop and implement harmonised method for wind power capacity value assessment for use in generation adequacy forecast and planning.	✓	✓		✓	✓

		Stakeholders				
		Wind industry	TSOs and power sector	EU and national energy regulators	EU and national govern-ments	Traders, market operators, users
Grid connection requirements	Two-step harmonisation of network connection requirements for wind power: structural and technical harmonisation.	✓	✓	✓	✓	
	Specific wind power code in the framework of the European network code.	✓	✓	✓		
	Further develop technical basis for connection requirements jointly between TSOs and wind industry.	✓	✓			

		Stakeholders				
		Wind industry	TSOs and power sector	EU and national energy regulators	EU and national govern-ments	Traders, market operators, users
Grid infrastructure upgrade	Reinforce and expand European transmission grids to enable predicted future penetration levels of wind power. The regularly updated TYNDP drafted by the European TSOs (ENTSO-E) should reflect the realistic wind power generation forecasts by providing sufficient traces of adequate capacity. New technologies such as underground HV DC VSC should be used where it can accelerate the implementation.		✓	✓	✓	
	Optimise the use of the existing infrastructure and transmission corridors through dynamic line rating, rewiring with high-temperature conductors, power flow control devices, FACTS and improved operational strategies.		✓			
	Build a transnational offshore grid in stages, starting from existing TSO plans and gradually moving to meshed networks. Build demonstration projects of combined solutions to test the technical and regulatory concepts.	✓	✓	✓	✓	
	Accelerated development and standardisation of transmission technology, notably meshed HV DC VSC and related methods.	✓	✓		✓	
	Deploy innovative and effective measures such as 'smart grids', also termed 'active networks', 'intelligent grids' or 'intelligent networks', assisted by adequate monitoring and control methods to manage high concentrations of variable generation especially at distribution level.		✓	✓		✓
	Develop and deploy proper regulation for multistate transmission.		✓	✓	✓	
	Encourage large geographical spread of wind power through planning and incentives and interconnection.	✓	✓	✓	✓	
	Socialise costs of transmission and distribution upgrades.		✓	✓	✓	✓
	Recognise the benefits brought about by an improved European grid: savings in balancing costs and improved market functioning.	✓	✓	✓	✓	✓

		Stakeholders				
		Wind industry	TSOs and power sector	EU and national energy regulators	EU and national govern-ments	Traders, market operators, users
Power market design	Allow intra-day rescheduling of generation, interconnectors and establish cross-border day ahead and intraday markets all over Europe.	✓	✓	✓	✓	✓
	Pursue further market integration in Europe. Establish implicit capacity auctions of interconnectors.		✓	✓	✓	✓
	Participation of all generation – also slower plants – in intraday rescheduling.	✓	✓	✓		✓
	Allow for international exchange of reserve capacity.		✓	✓		✓
	Establish an EU market integration strategy by implementing a target model and roadmap covering forward, day-ahead, intraday and balancing markets as well as capacity calculation and governance issues. Regional initiatives should converge into a single European market by 2015. A single central auction office could be established in the EU.		✓	✓	✓	✓
	Make transparent and regularly updated information available to all market players in order to analyse the best market opportunities.		✓	✓	✓	✓
	Adequate mechanisms for market monitoring should be put in place. Consequently, the competent authorities must have full access to all relevant information in order to monitor activities and implement any ex-post investigations and necessary measures to mitigate market power or prevent potential abuse of it.			✓	✓	✓

		Stakeholders				
		Wind industry	TSOs and power sector	EU and national energy regulators	EU and national govern-ments	Traders, market operators, users
Institutional and regulatory aspects	Develop and deploy financing schemes for pan-European transmission.		✓	✓	✓	
	Develop harmonised planning and authorisation processes that fully support TEN-E and related mechanisms to enhance coordination between Member States on cross-border planning.		✓		✓	
	Coordination of initiatives to build an offshore grid. Develop business model for investing in the offshore grid.		✓	✓	✓	✓
	Establish regional committees and specific authorising bodies to support regional/ transnational infrastructure projects.		✓	✓	✓	
	Establish clear legal framework for cross-border transmission management through binding framework guidelines and network codes		✓	✓	✓	✓
Research & Development	Solutions for connecting offshore wind farms to HVAC and DC lines.	✓	✓		✓	
	Wind plant capabilities for providing system support, and novel control and operating modes such as a Virtual Power Plant.	✓	✓		✓	
	Balancing power systems and market operation in view of future power systems with increased flexibility.	✓	✓		✓	
	Transmission technologies, architecture and operational tools.	✓	✓		✓	
	More active distribution networks and tools for distributed renewable management and demand-side response.	✓	✓		✓	✓
	Tools for probabilistic planning and operation, including load and generation modelling, short-term forecasting of wind power and market tools for balancing and congestion management.	✓	✓		✓	✓


Photo: Thinkstock

6 EUROPEAN RENEWABLE ENERGY GRID VISION 2010-2050

Objective

The grid map depicts the evolution of wind energy and other renewables in the European power system up to 2050. The map identifies the main renewable electricity production areas and consumption areas, and shows where the major power corridors would be situated in an integrated electricity market.

The map aims to outline the way to a renewable, fully integrated European power system by 2050, provided that the necessary grid infrastructure is developed and the market is fully integrated.

The grid map is made up of maps for five different years: 2010, 2020, 2030, 2040 and 2050. Each of these maps shows the main production areas and consumption areas and the corresponding dominant power flows along the transmission corridors. In this way, the reader can analyse the evolution of the main power generation capacities, the principle transmission routes, and the dominant power flows of specific generation sources along those transmission routes over time.

Legend

The grid maps depict the evolution of renewable energy in the European power system up to 2050.

Production sources

The main on-land and offshore renewable energy producing areas are shown. Each source is represented by a different icon.

Onshore and offshore wind

Hydro

Ocean

Biomass

Solar

In order to indicate the general location of the generation sources, shaded bubbles have been incorporated into the map. These bubbles vary in size according to the relevance and penetration level of the corresponding generation source in the different areas and timeframes[17].

Wind energy production area

Hydro energy production area

Ocean energy production area

Biomass energy production area

Solar energy production area

The five countries with the highest electricity consumption were identified and a corresponding icon was added according to their approximate higher consumption area[18].

Main consumption area

Power corridors

The main transmission corridors[19] are coloured according to the dominant renewable energy source flowing across them; this does not mean that there are no other power production sources using those transmission routes.

Power corridor

[17] The main sources of information were EWEA, OffshoreGrid, and the Greenpeace-EREC [R]evolution scenarios. Based on these sources, 3E identified the main types of power generation, their locations and possible penetration levels for the different years.

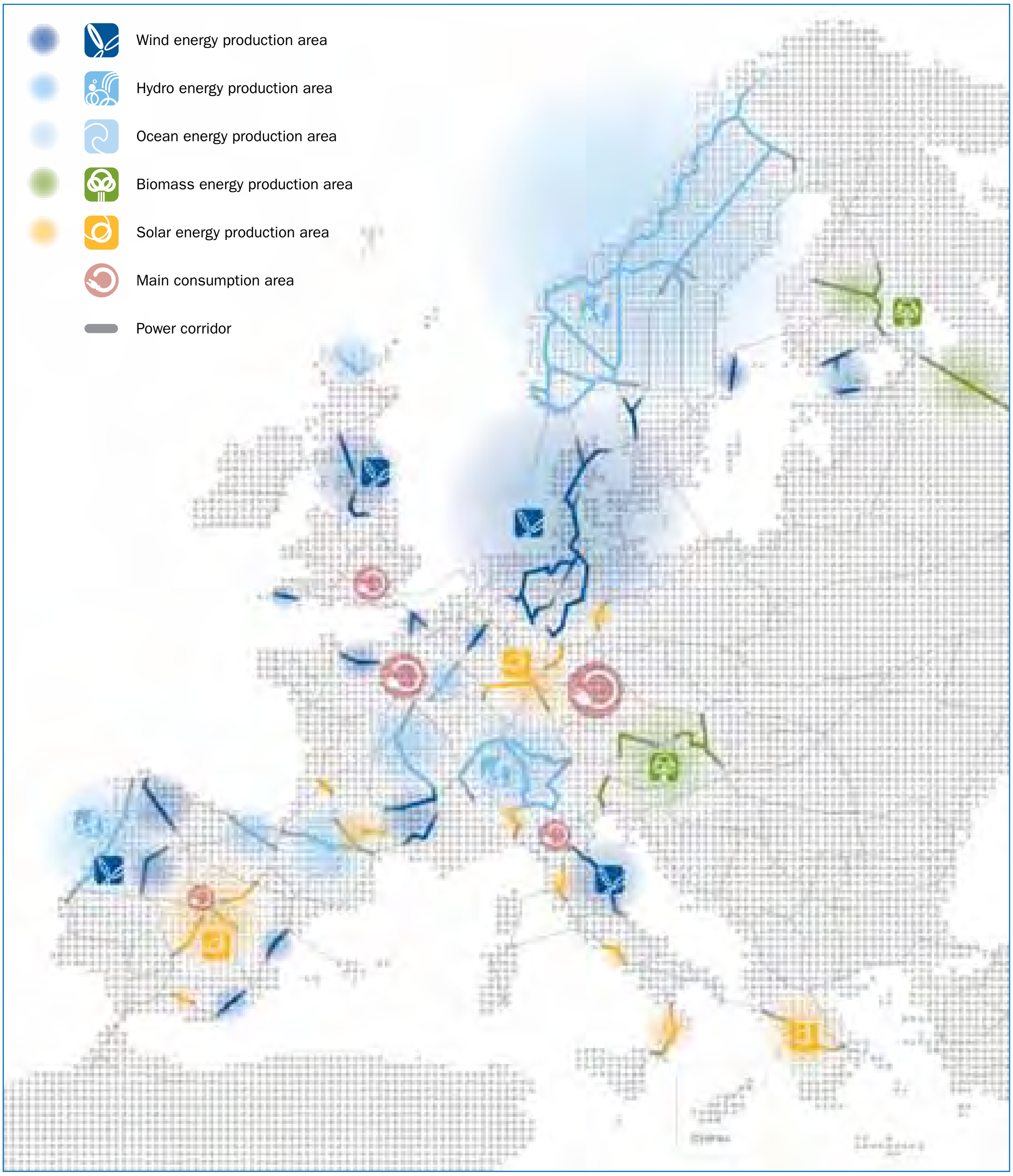
[18] Data from European Commission, Directorate-General for Energy, EU Energy Trends to 2030 – Update 2009, ICCS-NTUA for EC, 4 August 2010.

[19] Transmission lines were based on the current UCTE map, the ENTSO-E ten year development plan, and EWEA's 20 Year Offshore Network Development Master Plan.

European renewable energy grid

2010

This map shows the current role of renewable energy sources in a fragmented power system. After hydro, wind is the largest renewable power generation source,with around 4.8% of EU electricity demand. Wind energy already has a considerable share in the Northern German, Danish and Iberian power systems.

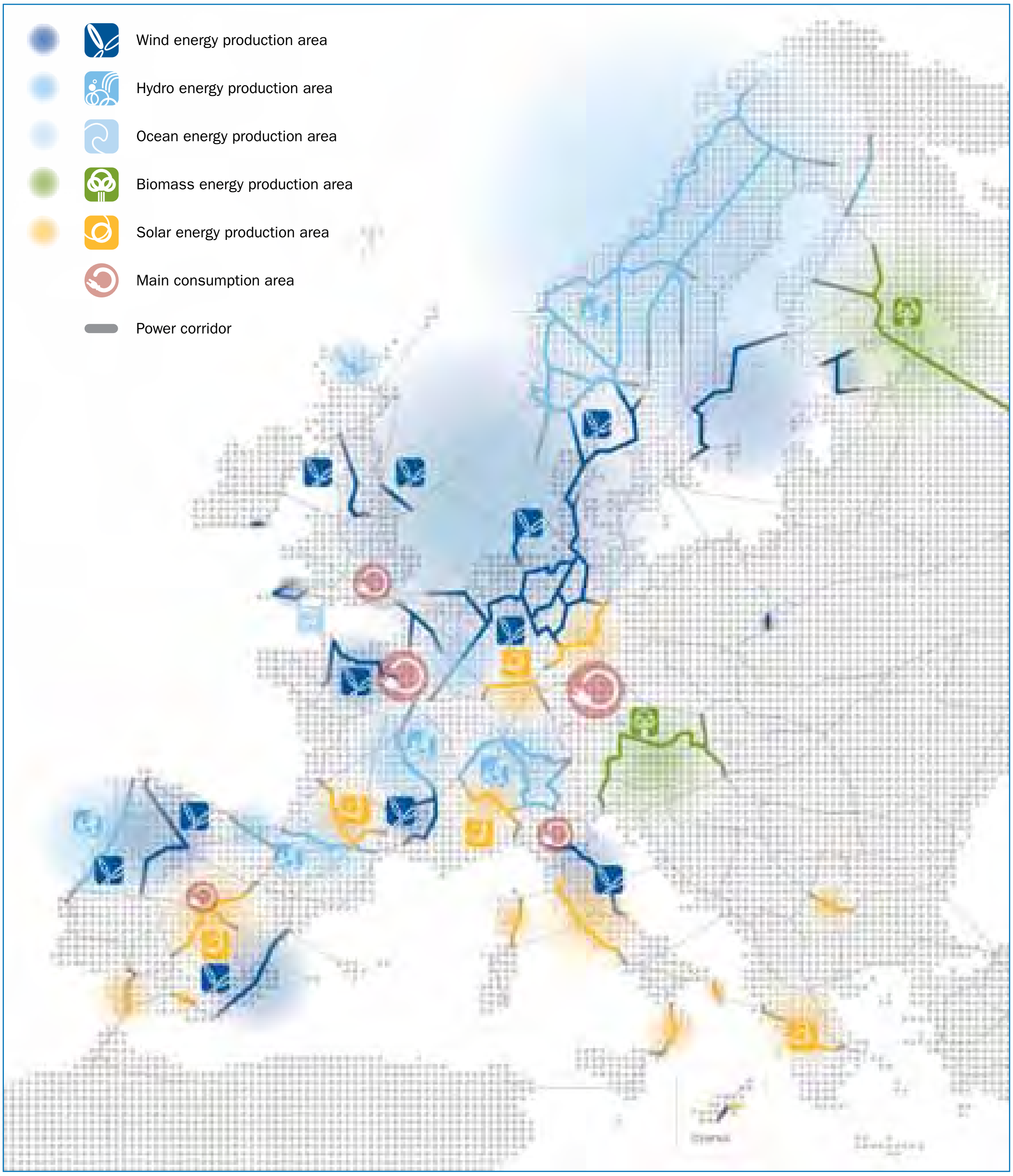


Design: www.onehemisphere.se

European renewable energy grid

2020

The map for 2020 – the target year of the 2009 Renewable Energy Directive - shows the increasingly important role of renewable energy. In 2020, 230 GW of wind power is expected to supply between 14 and 18% of EU electricity demand, of which 40 GW would be offshore. Wind energy becomes more significant in the North Sea neighbouring countries, the Baltic Sea and in the Iberian Peninsula.

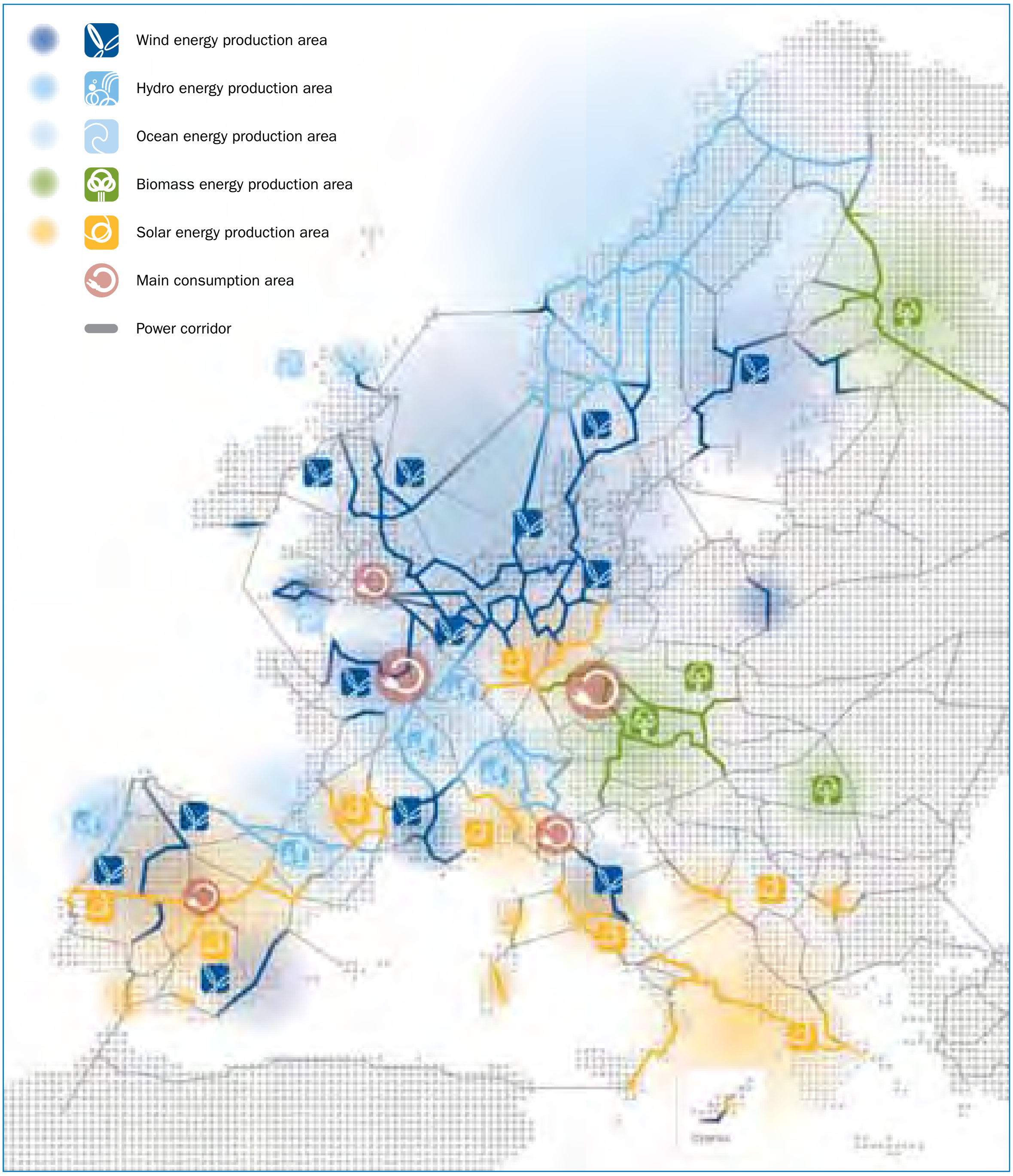


Design: www.onehemisphere.se

European renewable energy grid

2030

Renewable energy significantly increases from 2020 to 2030. This map shows the dominant role of wind power in the North Sea neighbouring countries, much facilitated by the development of the North Sea offshore grid. It also represents the growing role of photovoltaic (PV) and concentrated solar power (CSP) in the Southern European and biomass in Eastern European systems.

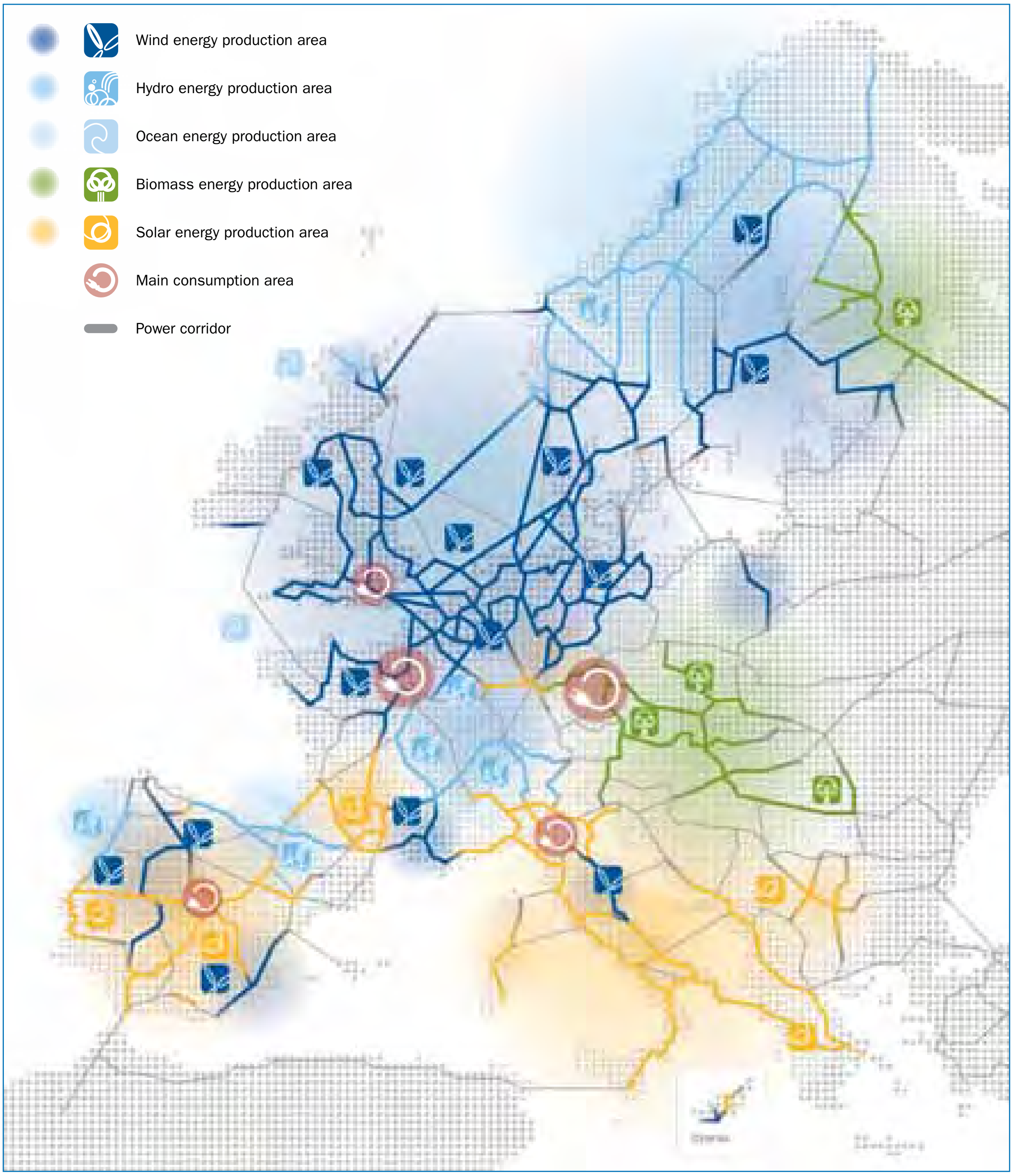


Design: www.onehemisphere.se

European renewable energy grid

2040

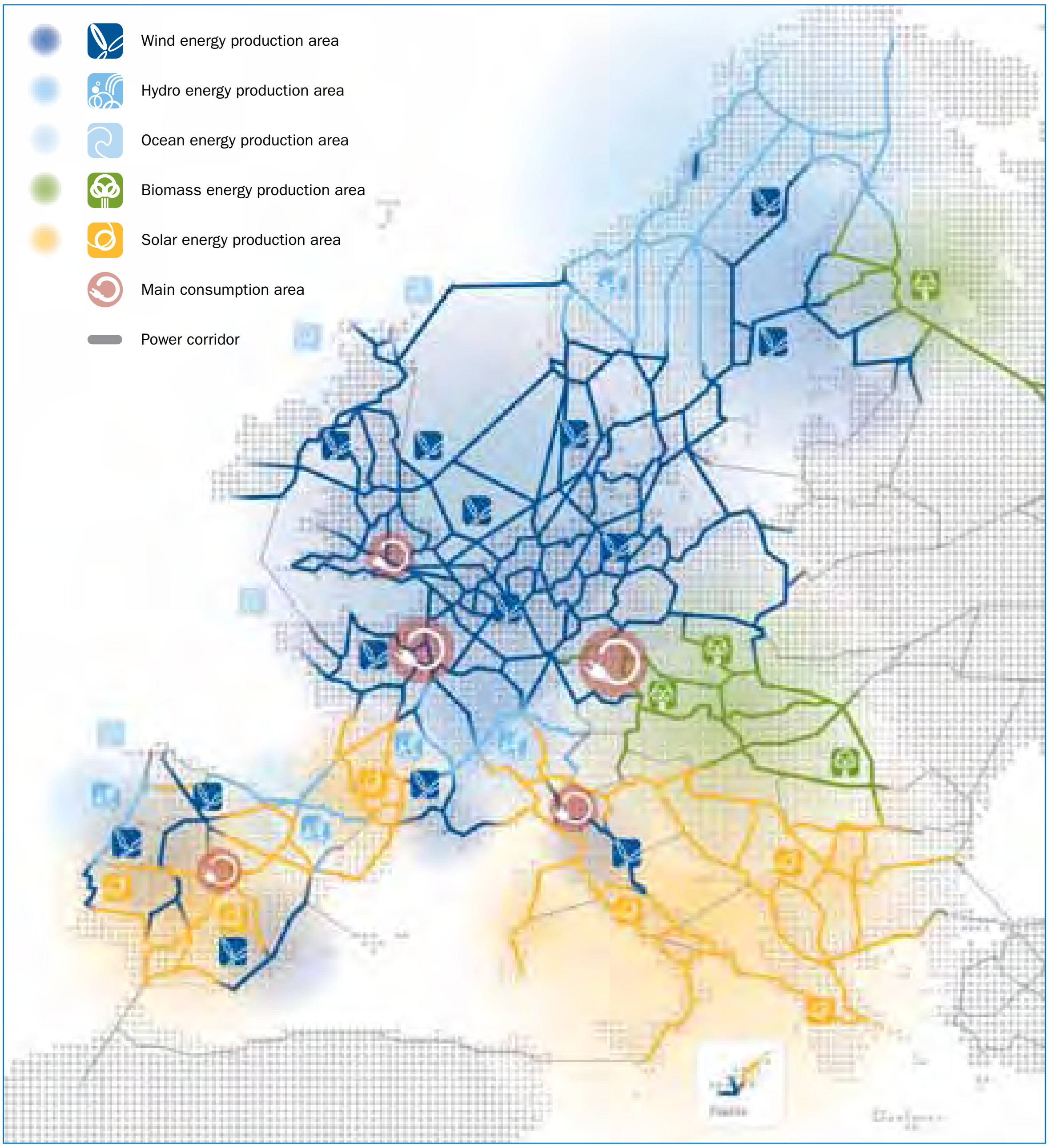
Due to increased power demand and a more integrated electricity market, renewable energy penetration levels increase significantly by 2040. Wind power in the North and Baltic sea neighbouring countries, hydro in Scandinavia and in the Alps, PV/CSP in Southern Europe, biomass in eastern Europe and marine renewables in the North Atlantic area, will all contribute.



Design: www.onehemisphere.se

European renewable energy grid 2050

In 2050 the system operates with 100% renewables, with the necessary grid infrastructure in place and full market integration. Wind power will meet up to 50% of Europe's electricity demand, dominating in the North Sea and Baltic Sea areas, and the Iberian Peninsula, Southern France and Central Italy. Variable renewables will be balanced with hydro power production in Scandinavia, the Alps and the Iberian Peninsula. Photovoltaic and concentrated solar power will play a crucial role in the Southern European power market, and biomass generation in Central and Eastern European countries.



Design: www.onehemisphere.se


Photo: EDF

2 WIND GENERATION AND WIND PLANTS: THE ESSENTIALS

1 WIND GENERATION AND WIND FARMS – THE ESSENTIALS

Although on a system-wide level wind power plants generate electricity just like any other plant, wind power has quite distinctive generation characteristics compared to conventional fuels. Firstly, there is the technical concept of the wind power plant. But perhaps more importantly, there is the variable nature of the wind resource driving the wind plant. Understanding these distinctive characteristics and their interaction with the other parts of the power system is the basis for integrating wind power into the grid.

1.1 Wind power plants

Wind power plant characteristics

In this section, the essential technical characteristics of wind power plants are described to facilitate understanding of their interaction with the electricity grid. This discussion is further divided into the wind turbine concept itself and the concepts used for wind power plants.

Wind turbine electrical concepts

Grid connected wind turbines have gradually evolved over the last 30 years from simple constant speed turbines to fully variable speed systems that enable active output control. In much of the older generation technology, the wind turbine rotor speed is fixed by the frequency of the electricity grid, and the turbine operates below its peak efficiency in most of its operational wind speed range. This has proven to be a cost-effective and robust concept and it has been scaled up and optimised up to the 2 MW level.

The variable speed system uses power electronic converters that enable the grid frequency to be decoupled from real time rotational frequency as imposed by the instantaneous wind speed and the wind turbine control system. Variable speed operation enables performance optimisation, reduces mechanical loading and at the same time delivers various options for active 'power plant' control. An essential feature of variable speed wind turbines is an active blade pitch control system, allowing full control of the aerodynamic power of the turbine (almost comparable to the fuel throttle of a combustion engine or gas turbine). The decoupling of the electrical and rotor frequency absorbs wind speed fluctuations, allowing the rotor to act as a (accelerating and decelerating) flywheel, and thus smoothing out spikes in power, voltage and torque. It even enables the creation of "synthetic inertia[1]" which is important in weak and poorly interconnected power systems with high levels of wind power.

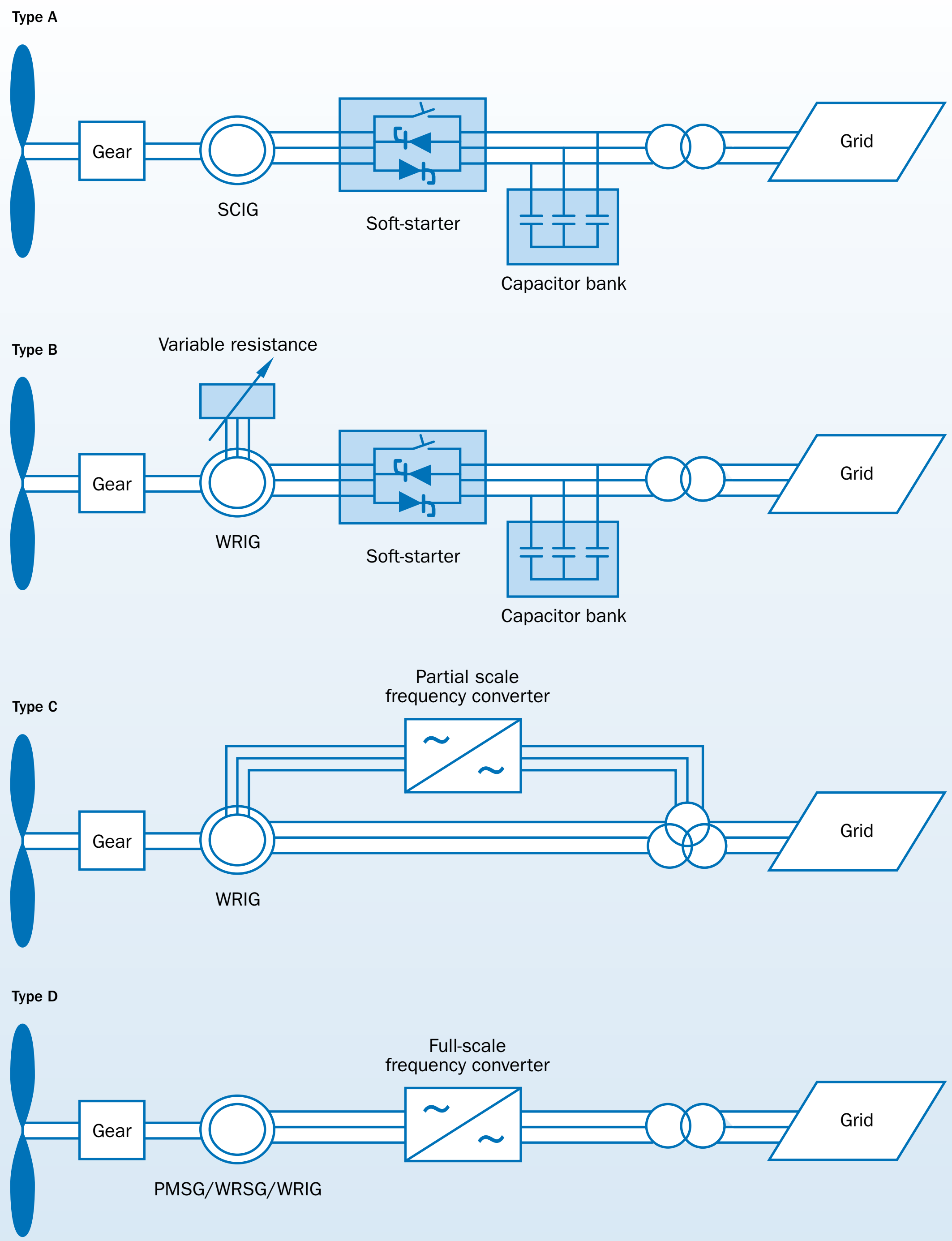
Until the turn of the century, the constant speed concept dominated the market, and it still represents a significant percentage of the operating wind turbine population in pioneering countries such as Denmark, Spain and regions of Germany. However, newly installed wind turbines are mostly variable speed wind turbines.

Considering the wide range of technologies available, it is useful to categorise electrical wind turbine concepts by type of generator (including power electronics) and by method of power control into four types A, B, C and D, as described by Table 1 overleaf.

The significant move towards the two last concepts (C + D represent almost 100% of sales in 2010 so far) shows the efforts the industry has made to adapt the design to the requirements of improved grid compatibility with increasing wind power penetration. (The term 'wind power penetration' indicates the fraction of the gross (annual) electricity consumption[2] that is covered by wind energy). Today's share of the more flexible wind turbine types accounts for approximately 75%[3] of the total installed and operating wind turbine population worldwide. Because of historical factors (periods of strong market growth), as well as commercial (market position of manufacturers) and technical ones (grid codes) there can be large regional differences in the (cumulative) distribution of the wind turbine types in specific regions or countries. Especially in the first-mover countries (Germany, Denmark and Spain) there still is a significant amount of type A technology although this is rapidly changing, for example through repowering. For example, in Spain[4] the distribution is: Type A - 18%; Type B - 0%; Type C - 77%; Type D - 5%.

[1] Inertia: for a definition plus brief explanation see glossary.
[2] There are many ways to define 'penetration level'. For example, wind power penetration can also be indicated as the total wind power generating capacity (MW) in relation to peak load in the system area. If this meaning is used, it will be explicitly mentioned, and referred to as 'capacity penetration'. 'Energy penetration' is preferred in this report, because the majority of studies reviewed measure wind power's penetration in terms of its coverage of annual electricity consumption.
[3] Own estimation based on market reviews by BTM Consult (2009) and EER (2009).
[4] Based on data from AEE (Spanish wind turbine manufacturers association) 2010.

FIGURE 1: TYPICAL WIND TURBINE ELECTRICAL CONFIGURATIONS



SCIG= squirrel cage induction generator; WRIG = wound rotor induction generator; PMSG = permanent magnet synchronous generator; WRSG = wound rotor synchronous generator

TABLE 1: OVERVIEW OF WIND TURBINE CONCEPTS

Type of system	Description	Manufacturer and type	Power plant capabilities	European market share per type class (cumulative)
Type A Fixed speed (one or two speeds)	Introduced and widely used in the 80s, the concept is based on a 'squirrel cage' asynchronous generator (SCIG), its rotor is driven by the turbine and its stator directly connected to the grid. Its rotation speed can only vary slightly (between 1% and 2%), which is almost a "fixed speed" in comparison with the other wind turbine concepts. The concept exists both in single speed and double speed versions. The double speed operation gives an improved performance and lower noise production at low wind speeds. Aerodynamic control combined with a type A concept is mostly passive stall, and as a consequence there are few active control options, besides connecting and disconnecting, especially if there is no blade pitch change mechanism. The concept has been continuously improved, for example in the so-called active stall designs, where the blade pitch angle can be changed towards stall by the control system.	Suzlon Nordex Siemens Bonus Ecotecnia	Voltage control Reactive power control	15%
Type B Limited variable speed	Type B wind turbines used by Vestas in the 80s and 90s. are equipped with a 'wound rotor' induction generator (WRIG). Power electronics are applied to control the rotor's electrical resistance, which allows both the rotor and the generator to vary their speed up to and down ± 10% during wind gusts, maximising power quality and reducing the mechanical loading of the turbine components, (at the expense of some minor energy loss, however). The wind turbines of type B are equipped with an active blade pitch control system.	Vestas (V27, V34, V47)	Voltage control (power quality)	5%
Type C Improved variable speed with DFIG	The type C concept combines the advantages of previous systems with advances in power electronics. The induction generator has a wound rotor, which is connected to the grid through a back-to-back voltage source converter that controls the excitation system in order to decouple the mechanical and electrical rotor frequency and to match the grid and rotor frequency. The application of power electronics provides control of active and reactive power, enabling active voltage control. In this type of system, up to approximately 40% of the power output goes through the inverter to the grid, the other part goes directly to the grid, and the window of speed variations is approximately 40% up and down from synchronous speed.	GE Repower Vestas Nordex Gamesa Alstom Acciona Windpower Suzlon Bard Kenersys	Reactive power Voltage control Fault ride through	55%
Type D Variable speed with full-scale frequency converter	Type D wind turbines come with the classical drive-train (geared), in the direct-drive concept (with slow running generator) and even in a hybrid version (low step-up gearbox, and medium speed generator). Various types of generators are being used: synchronous generators with wound rotors, permanent magnet generators and squirrel cage induction generators. In type D wind turbines the stator is connected to the grid via a full-power electronic converter. The rotor has excitation windings or permanent magnets. Being completely decoupled from the grid, it can provide an even wider range of operating speeds than type C, and has a broader range of reactive power and voltage control capacities.	Enercon MEG (Multibrid) GE Winwind Siemens Leitner Mtorres Lagerwey	Reactive power Active power Voltage control Fault ride through	25%

Wind power plant concepts and grid-friendly wind turbines

Wind turbines are usually placed in clusters (wind farms), with sizes ranging from a few MW up to several 100 MW. These clusters are connected to the grid as single generation units, therefore the term *wind plants* is the best suited. Whereas initially the emphasis on wind farm design was mainly on efficient and economic energy production that respected the rules of the grid operators, nowadays, with increasing wind power penetration, the demands of the grid operators have changed. In response to these demands, modern wind turbines and wind farms have developed the concept of the so-called wind energy power plant. The concept is essentially a wind farm with properties similar to a conventional power plant, with the exception that the fuel injection is variable. The operation of a wind energy power plant is designed in such a way that it can deliver a range of ancillary services to the power system. Its control system is designed such that the power can be actively controlled, including ramping up and down similar to conventional generation plants. Wind power plants can and do positively contribute to system stability, fault recovery and voltage support in the system.

The properties described above greatly enhance the grid integration capability of wind power. In order to achieve high penetration levels, active control properties are essential to optimally share the power supply tasks together with other plants and to enhance network security. Section 2 explains how these wind power plant capabilities are reflected in network connection codes, and how specific wind power technologies are able to meet these requirements.

For essential power plant services, wind plants become comparable to conventional plants, as illustrated in Table 2, where the maximum possible values for both technologies are shown. Differences will remain due to the nature of variable generation dictated by meteorological input.

TABLE 2: A COMPARISON OF POWER PLANT CAPABILITIES OF GRID FRIENDLY WIND PLANTS AND CONVENTIONAL PLANTS

Item	Wind plant	Conventional plant
Power factor range	+0.9 to –0.9	+0.85 to -0.85
Power stabilisation (active power control)	Curtailment	Curtailment
	Ramp rate control	Ramp rate control
Power dispatch	Based on short-term forecast (+/-10%)	Full dispatch
Frequency response	Droop	Droop
Operation control and reporting	SCADA	DCS system

The lighter coloured areas indicate where a wind plant is different from conventional plants. Source: GE

Wind power performance indicators

An essential difference between wind plants and conventional power plants is that the output of wind plants very strongly depends on the characteristics (mainly the local wind climate) of the site where they are installed. The rated power, also known as the nameplate power, is the maximum power, which is reached only 1% to 10% of time. Most of the time wind turbines operate at partial load, depending on the wind speed. From the point of view of the power system, wind turbines can be regarded as production assets with an average power corresponding to 20 to 40% of the rated power, with peaks that are three to five times higher.

Wind power performance indicators are related to the principal wind turbine specifications, that is rated power, and rotor diameter. The specific rated power[5] is in the range of 300 – 500 W/m², where the area is the "swept area" of the rotor. Wind turbine electric power output is measured according to IEC 61400-12 [IEC 2005] and is represented in a power curve (Figure 2).

[5] Ratio between the wind turbine's swept area (proportional to primary wind energy capture) and the nameplate (rated) power output.

FIGURE 2: WIND TURBINE POWER CURVE (LEFT) AND EXAMPLE OF AN AGGREGATED WIND FARM POWER CURVE USED FOR REGIONAL ASSESSMENTS AND FORECASTS (RIGHT)

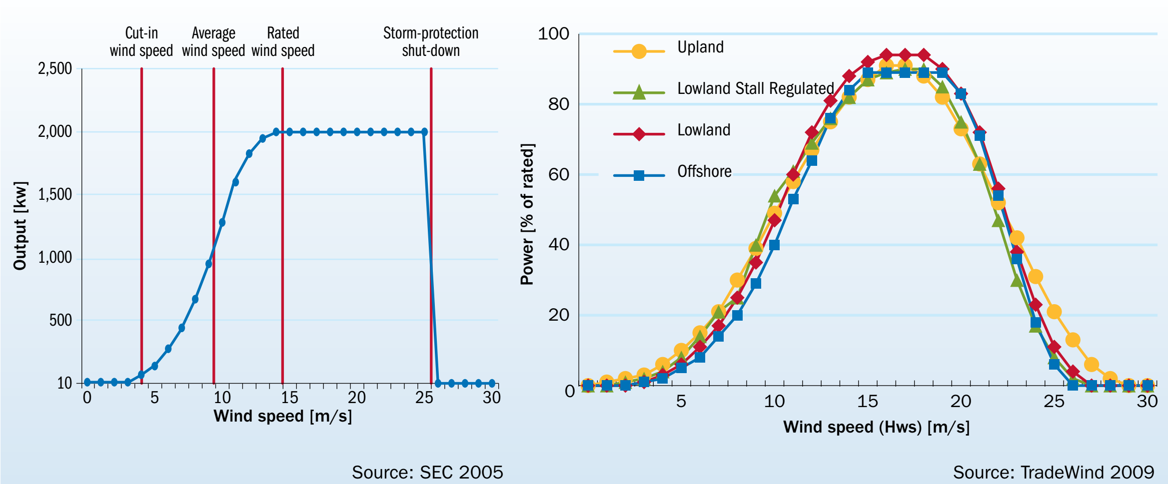


TABLE 3: WIND TURBINE CHARACTERISTICS (EXTRACTED FROM MARKET INFORMATION AND OPERATIONAL STATISTICS)

Wind turbine characteristic	<Range>, typical value
Rated power (MW)	<0.850 – 6.0>, 3.0
Rotor diameter (m)	<58 – 130>, 90
Specific rated power (W/m²)	<300 – 500>, 470
Capacity factor (=load factor)* onshore / offshore (%)	<18 – 40> / <30 – 45>
full load equivalent* onshore / offshore (h)	<1,600 – 3,500>/ <2,600 – 4,000>
Specific annual energy output** (kWh/m² year)	<600 – 1,500>
Technical availability*** (%)	<95 – 99>; 97.5

** annual base, depends largely on the site's average wind speed and on matching specific power with the site's average wind speed*

*** normalised to rotor swept area, value depends on site average wind speed and wind turbine performance*

**** values valid onshore, including planned outages for regular maintenance*

The power curve is used to estimate energy output at well defined site specific wind regimes (characterised by hub height wind speed and wind direction long-term frequency distribution). The energy output is standardised to long-term[6] average annual energy output. The power curve is also used to derive the power output in short-term forecasting from 10-minute average wind speed values generated by forecast models. For power system studies, so-called regionally averaged power curves are used, as shown in Figure 2 [TradeWind 2009]. The typical values of the wind turbine technology installed today are given in Tables 3 and 4.

6 Long-term: indicative time scale is a wind turbine's technical design lifetime i.e. 20 years.

TABLE 4: WIND FARM CHARACTERISTICS

Wind farm characteristic	<Range>, typical value
Rated wind farm sizes (MW)	<1.5 – 500>
Number of turbines	1 – several hundreds
Specific rated power offshore (MW/km²)	<6-10>
Specific rated power onshore (MW/km²)	<10-15>
Capacity factor (=load factor)* onshore / offshore (%)	<18 – 40> / <30 – 45>
Full load equivalent* (h)	<1,600 – 3,500> onshore/ <2,600 – 4,000> offshore
Specific annual energy output onshore** (GWh/km² year)	30 - 40
Specific annual energy output offshore** (GWh/km² year)	20 – 50
Technical availability*** (%)	<95 – 99>; 97

** annual base, depends largely on the site's average wind speed and on matching specific power and site average wind speed*

*** per km² ground or sea surface*

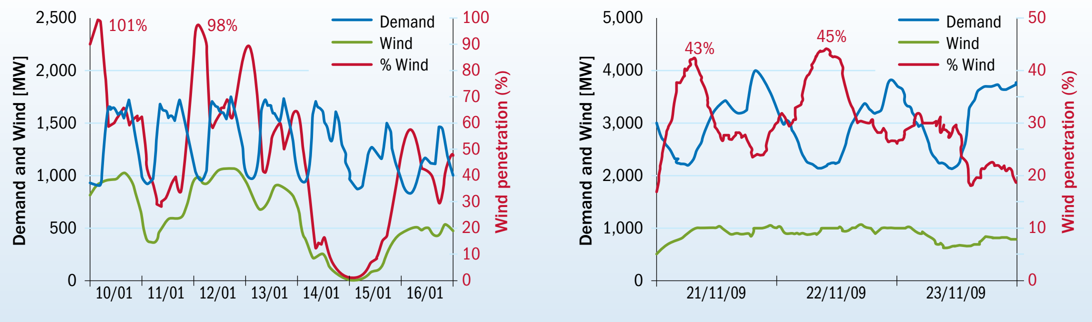
**** values valid onshore, including planned outages for regular maintenance*

1.2 Variability of wind power production

Wind power: variable generation embedded in a variable electricity system

Wind power fluctuates over time, mainly under the influence of meteorological conditions. The variations occur on all time scales: seconds, minutes, hours, days, months, seasons, years. Understanding these variations and their predictability is of key importance to the integration and optimal utilisation of the power system. Both demand and supply are inherently variable in electric power systems, and are designed to cope with this variability in an efficient way. Electrical demand is highly variable, dependent on a large number of factors, such as the weather (ambient temperature), daylight conditions, factory and TV schedules, and so on. The system operator needs to manage both predictable and unpredictable events in the

FIGURE 3: WIND ENERGY, ELECTRICITY DEMAND AND INSTANTANEOUS PENETRATION LEVEL IN WEST DENMARK FOR A WEEK IN JANUARY 2005 (LEFT) AND IRELAND FOR 3 DAYS IN NOVEMBER 2009 (RIGHT)



Source: www.energinet.dk

Source: www.eirgrid.com

grid, such as large conventional generators suddenly dropping off line and errors in demand forecast. Obviously, as illustrated in Figure 3, wind energy's share of production – which can be quite high - determines how much system operation will be affected by wind variability.

Variable versus intermittent generation

Wind power is sometimes incorrectly considered to be an intermittent generator. This is misleading. At power system level, wind power does not start and stop at irregular intervals (which is the meaning of intermittent, and which is a characteristic of conventional generation). Even in extreme events such as storms it takes hours for most of the wind turbines in a system area to shut down. For example in the storm of 8 January 2005, it took six hours for the aggregated wind power in Western Denmark to shut down from 90% to 10% production. Moreover, periods with zero wind power production are predictable and the transition to zero power is gradual over time. It is also worthwhile considering that the technical availability of wind turbines is very high (98%) compared to other technologies. Another advantage of wind power in this respect is its modular and distributed installation in the power system. Breakdown of a single unit has a negligible effect on the overall availability. Thus, the term intermittent is inappropriate for system wide wind power and the qualifier variable generation should be used.

Short-term variability

For grid integration purposes, the *short-term variability* of wind power (from minutes to several hours) is the most important. It affects the scheduling of generation units, and balancing power and the determination of reserves needed. The short-term variability of wind power, as experienced in the power system, is determined by short-term wind variations (weather patterns), and the geographical spread of wind power plants.

The total variability experienced in the power system is determined by simultaneous variations in loads for all wind power plants and other generation units. The impact of the short-term variation of wind power on a power system depends on the amount of wind power capacity and on many factors specific to the power system in question (generation mix, degree of interconnection), as well as how effectively it is operated to handle the additional variability (use of forecasting, balancing strategy).

Analysing the available power and wind measurements at typical wind plant locations allows the variations in net power output expected for a given time period, i.e. within a minute, within an hour or over several hours, to be quantified. The distinction between these specific time scales is made because this type of information corresponds to the various types of power plants for balancing. Experience and power system analyses show that the power system handles this short-term variability rather well.

Variations within the minute: not a noticeable impact

The fast variations (seconds to one minute) of aggregated wind power output as a consequence of turbulence or transient events are quite small as can be seen in the operational data of wind farms. As a result they are hardly felt by the system.

Variations within the hour are felt by the system at larger penetration levels

These variations (10-30 minutes) are not easy to predict, but they even out to a great extent with geographic dispersion of wind plants. Generally they remain within ±10% of installed wind power capacity for geographically distributed wind farms. The most significant variations in power output are related to wind speed variations in the range of 25 – 75% of rated power, where the slope of the power curve is the steepest. The variations within an hour are significant for the power system and will influence balancing capacities when their magnitude becomes comparable to variations in demand; in general this will be from wind energy penetration levels of 5 to 10% upwards.

Variations in hourly timescale: predictable, but cause large amounts of uncertainty

Hourly, four-hourly and 12-hourly variations can mostly be predicted and so can be taken into account when scheduling power units to match the demand. In this time scale it is the uncertainty of the forecasts (predicted forecast *error*) that causes balancing needs, not the predicted variability itself. The system operator always considers the uncertainty of wind power predictions in relation to the errors in demand forecasts and other plant outages. The extent of hourly variations of wind power and demand are shown in Table 5. It is useful to express these wind power variations as a percentage of installed wind power capacity. Extensive studies have been done in many countries and an overview of the conclusions is given in Table 5 [Holttinen, 2009].

When looking at wind power producing areas (instead of wind plants) it takes hours for most of the wind power capacity to go offline during a storm. Example: for the storm in Denmark on 8 January 2005 – one of the biggest storms Denmark has seen in decades – it took six hours for the 2,400 MW of wind power in the West Denmark area (200 km^2) to drop from 2,000 MW to 200 MW. The loss of power from a concentrated offshore wind farm area could happen within an hour. If most of the capacity comes from concentrated large offshore wind farms, a control method of not shutting down the turbines completely in storms is recommended. The passage of a storm front can be predicted and appropriate control should be adopted to minimise the effects.

Extreme cases affecting system operation concern large active power output variations that have been wrongly predicted, e.g. a storm front prediction which contains uncertainty about how much wind power generation will be reduced as a result of it. Here, the accuracy of the prediction tools is of prime importance, as the next section will discuss. Moreover, technical possibilities for controlling the output of wind turbines to reduce a steep gradient in output power when a storm front is passing a wind farm exist – for example by using wind turbines provided with a 'storm control' mode. However, ramp rates still can be quite significant when considering small areas.

For a larger geographical area, measures include the setting of a temporary cap on the output of all wind farms, the limitation of the maximum rate of change of wind farm output (ramp rate), for example by staggered starting or stopping, or by reducing positive ramp rates. Wind farms are highly controllable in this respect. Clearly, limiting the output of wind generation wastes "free" energy from a capital intensive power plant and should only be done when other means have been exhausted.

TABLE 5: EXTREME SHORT-TERM VARIATIONS OF LARGE-SCALE REGIONAL WIND POWER, AS % OF INSTALLED WIND POWER CAPACITY, FOR DIFFERENT TIME SCALES

			10-15 minutes		1 hour		4 hours		12 hours	
Region	Region size	Numbers of sites	Max decrease	Max increase	Max decrease	Max increase	Max decrease	Max increase	Max decrease	Max increase
Denmark	300x300 km^2	> 100			-23%	+20%	-62%	+53%	-74%	+79%
West-Denmark	200x200 km^2	> 100			-26%	+20%	-70%	+57%	-74%	+84%
East-Denmark	200x200 km^2	> 100			-25%	+36%	-65%	+72%	-74%	+72%
Ireland	280x480 km^2	11	-12%	+12%	-30%	+30%	-50%	+50%	-70%	+70%
Portugal	300x800 km^2	29	-12%	+12%	-16%	+13%	-34%	+23%	-52%	+43%
Germany	400x400 km^2	> 100	-6%	+6%	-17%	+12%	-40%	+27%		
Finland	400x900 km^2	30			-16%	+16%	-41%	+40%	-66%	+59%
Sweden	400x900 km^2	56			-17%	+19%	-40%	+40%		

Denmark, data 2000-2002 from http://www.energinet.dk; Ireland, Eirgrid data, 2004-2005; Germany, ISET, 2005; Finland, years 2005-2007 (Holmgren, 2008); Sweden, simulated data for 56 wind sites 1992-2001 (Axelsson et al., 2005); Portugal, INETI.

Of special interest for system operators is how wind variability affects the power flow in the transmission system. The TradeWind study investigated the effect of hourly wind power variations on the power flows in interconnectors. In addition to the observation that it is not easy to distinguish wind induced variations from other influences such as demand fluctuations, it appears that wind power forecast errors create significant uncertainty when predicting electricity flows in interconnectors.

Long-term variability

The slower or long-term variations of wind power that affect how wind power is integrated into the power system include the seasonal variations and inter-annual variations caused by climatic effects. These are not very important for the daily operation and management of the grid, but do play a role in strategic power system planning.

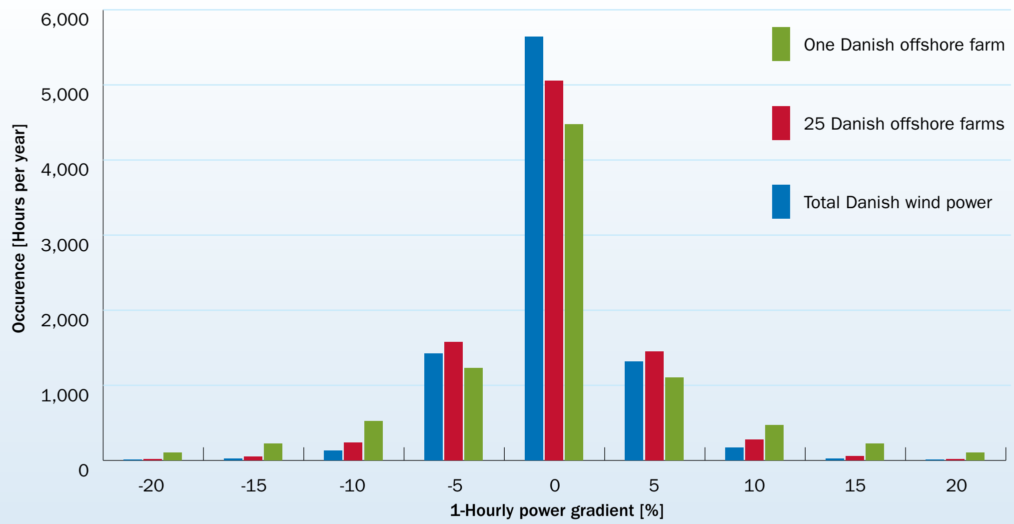
Monthly and seasonal variations: These variations are important to electricity traders who have to deal with forward contracts where wind power volume has an influence on the price. They are equally important for planning the power system. It appears that both for electricity trading and for system planning purposes, the deviations - as for example derived from annual statistics of produced wind power - can be sufficiently hedged.

Inter-annual variations: These variations are relevant for long-term system planning, but not for daily power system operation. The annual variability of the mean wind speeds at sites across Europe tends to be similar and can reasonably be characterised by a normal distribution with a standard deviation of 6%. The inter-annual variability of the wind resource is less than the variability of hydro inflow, for example. Finally, on a power system level the annual variations are influenced by the market growth of wind power and by the projected ratio of onshore to offshore wind power.

Benefits of aggregation from geographically dispersed sites

With a wide regional distribution of wind turbines, there is a low correlation between short-term and local

FIGURE 4: FREQUENCY OF RELATIVE POWER CHANGES IN 1 HOUR INTERVALS FROM A SINGLE OFFSHORE WIND FARM IN THE DANISH NORTH SEA, ALL EXPECTED DANISH OFFSHORE WIND FARMS IN 2030 (3.8 GW) AND ALL EXPECTED WIND FARMS (ONSHORE & OFFSHORE) IN DENMARK IN 2030 (8.1 GW)



A positive value reflects an increase in power and a negative value a decrease.

Data from the IEE-Project “OffshoreGrid” [Tambke 2010].

wind fluctuations and they largely balance each other out. This phenomenon has been studied extensively in many countries [Holttinen, 2009], and more recently in the European integration studies *TradeWind, EWIS* and *OffshoreGrid*. As a result the maximum wind power fluctuations experienced in the power system are reduced. This smoothing effect is illustrated in Figure 4. In this example the frequency of the positive and negative changes observed in the hourly averages of wind power output are obtained from simulated outputs from aggregated wind plants, based on the 2030 scenario. Figure 4 shows that with higher levels of aggregation the occurrence of large gradients (variations from hour to hour) diminishes. One wind farm can show variations of over 20% several hours per year, whereas the occurrence of variations of 15% is practically zero for the total amount of Danish wind power.

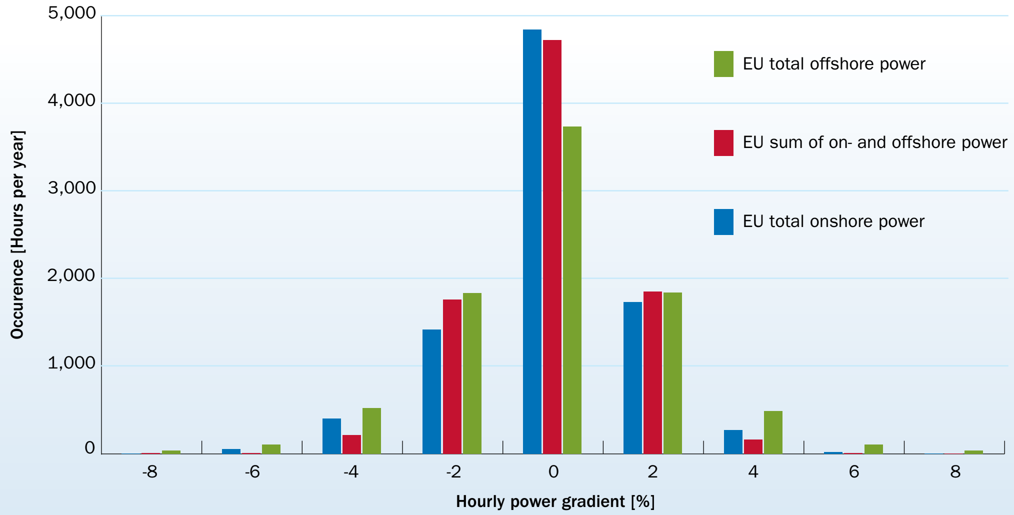
The effect is even more pronounced when aggregating at European scale, as shown in Figure 5. Whereas offshore EU wind power still exhibits gradients of 8% during a noticeable time, total EU wind power (onshore plus offshore) hardly shows hourly gradients in excess of 5%. The beneficial effect of aggregating offshore wind and onshore wind is also visible from Figure 5.

The smoothing effect on wind variability is clearly visible from Figure 6 where the variations of the wind power capacity factor (hourly values) over one month are shown for a small country (Belgium), a region of Europe (north-west) and for the whole of Europe.

A geographical spread of wind power plants across a power system is a highly effective way to deal with the issue of short term variability. Put another way, the more wind power plants in operation, the less impact from variability on system operation.

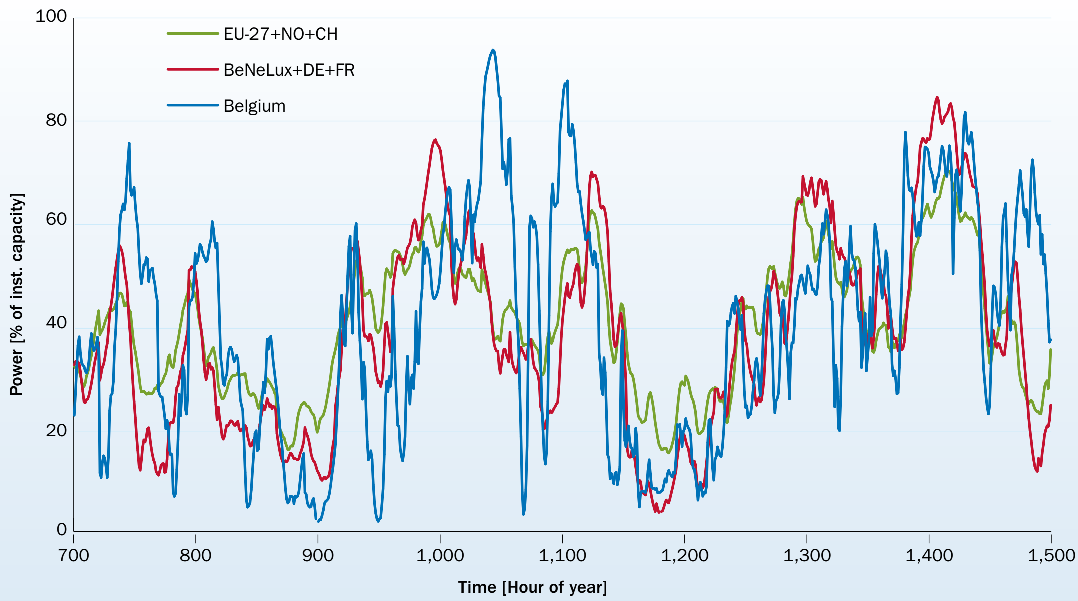
In addition to helping reduce fluctuations, the effect of geographically aggregating wind power plant output is an increased amount of firm wind power capacity in the system. In simple terms: the wind always blows somewhere. Furthermore, the wind never blows very hard everywhere at the same time. Wind power production peaks are reduced when looking at a larger area, which is important since absorbing power surges from wind plants is challenging for the system. The effect increases with the size of the area considered. Ideally, to maximise the smoothing effect, the wind speeds occurring in different parts of the system should be as uncorrelated as possible. Due to the typical size of

FIGURE 5: BASED ON SCENARIOS FROM THE IEE OFFSHOREGRID PROJECT FREQUENCY OF RELATIVE POWER CHANGES IN ONE HOUR INTERVALS FROM ALL EXPECTED EUROPEAN OFFSHORE WIND POWER PLANTS IN 2030 (127 GW), FROM ALL EXPECTED EUROPEAN ONSHORE WIND POWER PLANTS IN 2030 (267 GW) AND THE SUM OF ALL EXPECTED ON AND OFFSHORE CAPACITIES IN THE EU IN 2030 (394 GW)



A positive value reflects an increase in power and a negative value a decrease. The average output is 60 GW offshore and 64 GW onshore [Tambke 2010].

FIGURE 6: EXAMPLE OF THE SMOOTHING EFFECT BY GEOGRAPHICAL DISPERSION

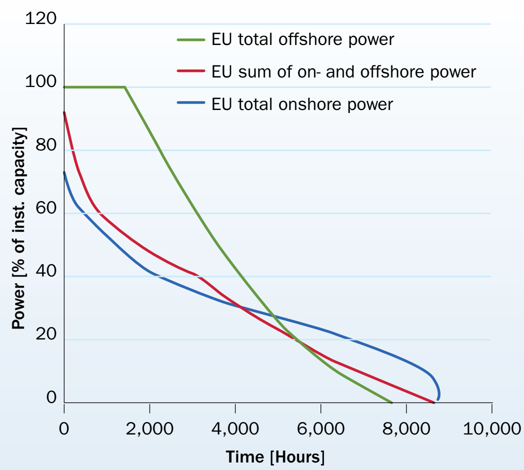


The figure compares the hourly output of wind power capacity in three areas, including all expected onshore and offshore wind power plants in the year 2030. This is calculated with wind speed data from February 2007 and simulated wind power from the IEE-Project "OffshoreGrid" [Tambke 2010].

weather patterns, the scale of aggregation needed to absorb a storm front is in the order of 1,500 km [Dowling, 2004]. By aggregating wind power Europe wide, the system can benefit from the balancing of high and low pressure areas over Europe. The economic case for smoothing wind power fluctuations through the use of transmission capacity is the subject of various European studies [TradeWind 2009, Woyte 2008, Tambke 2010], both for onshore and offshore wind power.

A way of representing the beneficial effect of aggregation at power system scale is the load duration curve of wind power plants, which gives the frequency distribution of the partial load states of generated wind power. Examples for a single wind turbine, a small country (Belgium) and the whole of the EU are given in Figure 7. Aggregating wind power flattens the duration curve. A single offshore turbine in this example produces rated power for 1,500 hours and zero power during 1,000 hours. At the scale of a small country, total output is almost never zero and never higher than 90% of installed capacity. For a large area like the

FIGURE 7: DURATION CURVES FOR THE 'WIND YEAR 2030'



(I) For a single offshore turbine off the Belgian coast (blue line), (II) for the sum of all expected onshore and offshore wind power plants in Belgium in 2030 (green line), and (III) for the sum of all expected onshore and offshore wind power plants in Europe in 2030 (red line) [Tambke 2010]

EU, the maximum wind power produced at a given moment is 70% of the total installed wind power capacity, whereas the minimum wind power production is never below 10% of the installed wind capacity. This demonstrates how aggregation at European scale results in increasingly steady wind power output.

More detailed studies [Roques, 2008] show that a more even distribution of wind plants over Europe would give an even smoother curve. Such studies develop guidelines for wind power plant planning and siting policies that support economic integration by minimising the amount of additional balancing costs due to the wind variability.

A very important conclusion is that large-scale wind power cannot be aggregated to an optimal extent without a well interconnected grid. In this perspective, the grid plays a crucial role in aggregating the various wind power plant outputs installed at a variety of geographical locations, with different weather patterns. The larger the integrated grid – especially beyond national borders - the more pronounced this effect becomes. This effect is exactly equivalent to the use of the grid to aggregate demand over interconnected areas.

1.3 Variability and predictability of wind power production

General

Accurate forecasts of the likely wind power output in the time intervals relevant to the scheduling of generation and transmission capacity allow system operators to manage the variability of wind power in the system. Prediction is key to managing wind power's variability. The quality of wind power prediction has a beneficial effect on the amount of balancing reserves needed. Thus, forecasting wind power is important to its cost-effective integration in the power system.

Today, wind energy forecasting uses sophisticated numerical weather forecasts, wind power plant generation models and statistical methods, to predict generation at five minute to one hour intervals over periods of up to 48-72 hours in advance, as well as for seasonal and annual periods.

Forecasting wind power production is different to forecasting other generation forms or forecasting the load[7]. There is extensive experience with demand (load) forecasting, and consumption is more predictable than wind power. The quality of wind power forecasts is discussed below, and we explain how the accuracy of wind power prediction improves at shorter forecast horizons and when predicting for larger areas. In addition, ways for further reducing forecast error are highlighted.

Forecasting tools

Short-term wind power prediction consists of many steps [Giebel, 2003]. For a forecasting horizon of more than six hours ahead, it starts with a Numerical Weather Prediction (NWP), which provides a wind prognosis, that is, the expected wind speed and direction in a future point in time. Subsequent steps involve applying the NWP model results to the wind power plant site, converting local wind speed to power, and applying the forecast to a whole region.

There are different approaches to forecasting wind power production. Typically, there are models that rely more on the physical description of a wind field and models that rely on statistical methods (Figure 8). Both statistical and physical models can appear in an operational short-term forecasting model.

The tools are also differentiated by different input data from the NWP model. Wind speed and direction at the wind power plant are used as a minimum. Some statistical and most physical models use additional parameters from the meteorological model, such as

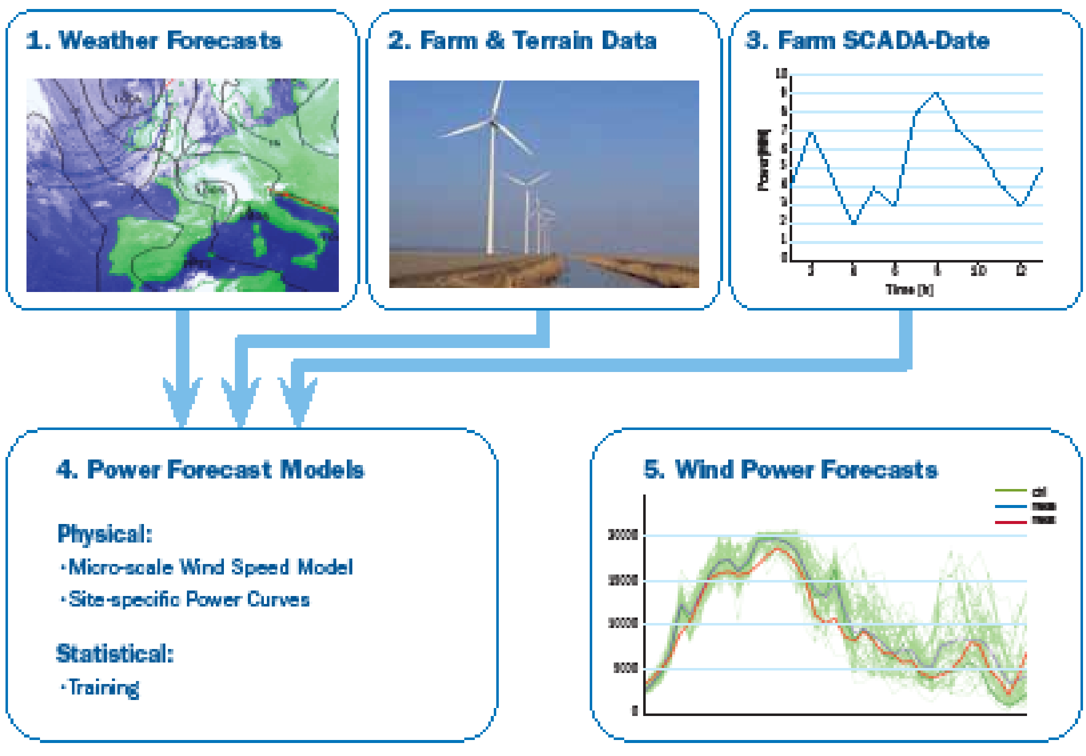
[7] Except unplanned outages of conventional plants which by nature are not predictable. In this respect, wind power often has an advantage because of its modular nature and due to the smaller amounts of capacity that go offline at any one time in the case of outages.

temperature gradients, wind speeds and directions at different heights above ground, and the pressure field. All models scale down results from the NWP model's coarse resolution, which in Europe for current models is between three and 15 km of horizontal resolution. In some areas with gentle terrain (Denmark, for example), this resolution is good enough for wind energy.

In complex terrain (for example Spain), such resolution does not capture all the local effects around the wind power plant. If this is the case, additional meso-scale or micro-scale models can be employed, using the whole meteorological field of the NWP model in a radius of up to 400 km around the wind power plant. When using statistical models, the influence of orography on the accuracy of the outcome is less marked, and experience in Spain shows good results for complex terrains. The science of short-term forecasting is developing very rapidly with remarkable results.

In general, advanced statistical models tend to do well in most circumstances, but they require data accumulated over half a year before they perform very well. Physical tools, on the other hand, can create forecasts even before the wind power plant is erected. Later on, they can be improved using measured data. Some physical tools, however, require large computing facilities. In this case, they have to be run as a service by the forecaster, while computationally less demanding models can be installed by the client.

FIGURE 8: OVERVIEW OF TYPICAL FORECASTING APPROACHES. WIND SPEED FORECAST DATA (1) ARE DELIVERED BY A NUMERICAL WEATHER PREDICTION (NWP) FROM A WEATHER SERVICE AND WIND POWER SCADA DATA (3) ARE PROVIDED BY THE WIND FARMS



The two data sets are combined to provide a forecast for future energy production [Tambke 2010]. The variety of forecast systems can be classified according to the types and combinations of input data and methods of computing (physical or statistical formulas). For very short term forecasts (1min-2hours) SCADA data have to be available in real-time. NWP systems today have different horizons, from short term (1h-12h), intra-day (6h-24h) and day-ahead (24h-48h) up to medium range (3-10 days) and long range (1-4 weeks) [see www.ecmwf.int].

Recent practice is to use a combination of different input models and a combination of forecast tools to achieve a higher performance, as will be illustrated below. Utilisation of the tools in system operation is explained in Chapter 3.

Accuracy of short-term wind power forecasting

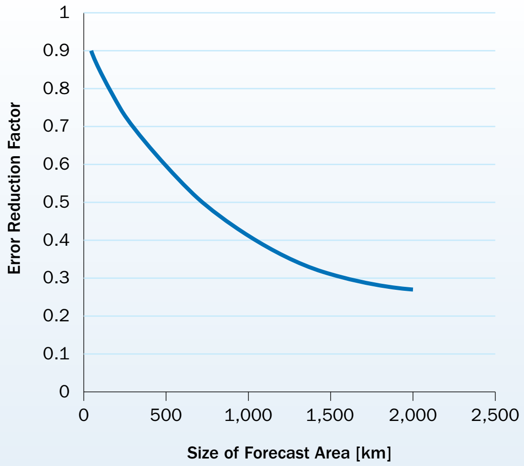
Two major factors have a significant influence on the performance and accuracy of forecast tools, namely the size of the area considered and the prediction horizon:

- Regardless of the forecasting method used, the forecast error (RMSE)[8] for a single wind power plant is between 10% and 20% of the installed wind power capacity for a forecast horizon of 36 hours, using current tools. After scaling up to aggregated wind power of a whole area the error drops below 10% due to the smoothing effects. The larger the area, the better the overall prediction is (see Figure 9).
- Forecast accuracy is reduced for longer prediction horizons. Thus, reducing the time needed between scheduling supply to the market and actual delivery (gate-closure time) would dramatically reduce unpredicted variability and, thereby, lead to a more efficient system operation without compromising system security.

The beneficial effect of using uncorrelated sites in forecasting is also seen by developers using a large geographically spread portfolio (Figure 10).

It is not sufficient only to look at the average forecast error. While it is possible to have reasonable *average* prediction accuracy, due to the stochastic nature of wind, large forecast errors occur relatively frequently – as opposed to, for example, demand forecast errors. In mathematical terms, the distribution of the error is not Gaussian, as illustrated in Figure 12. Large prediction errors occur relatively frequently. This is an important consideration for system reserve planning, as will be shown in Chapter 3. A way to cope with this is to use intra-day trading in combination with very short term forecasts (two to four hours) to reduce the forecast error.

FIGURE 9: DECREASING THE FORECAST ERROR OF WIND POWER PRODUCTION DUE TO SPATIAL SMOOTHING EFFECTS IN LARGER AREAS



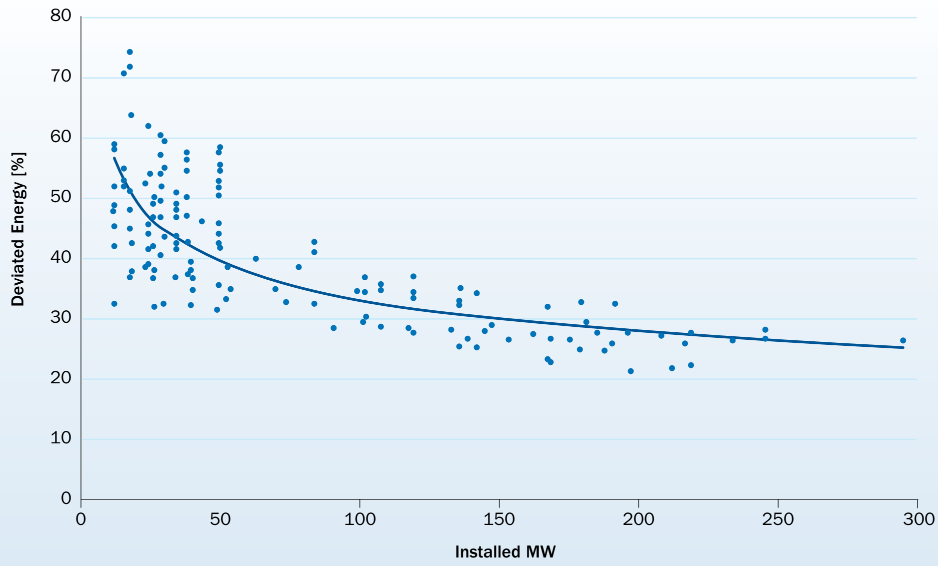
The error reduction factor is defined as the ratio of nRMSE of a single turbine forecast divided by the nRMSE of the forecast for the aggregated production of all wind plants in the respective area. The nRMSE is defined as the absolute RMSE divided by the installed capacity. It has to be noted that the nRMSE increases with increasing mean wind speed and increasing normalised mean production (capacity factor), e.g. it is higher for Scotland than for Germany even when using exactly the same NWP data and forecast system [Tambke 2010].

There has been quite a dramatic improvement in the performance of forecasting tools since the beginning of the century. The joint effects of smoothing and improved forecasting tools are reflected in the learning curves in Figure 13, showing the development over time of the average error in Germany.

Improvements have been made by using ensemble predictions based on input from different weather models in one tool and combined prediction using a combination of different prediction tools. This results

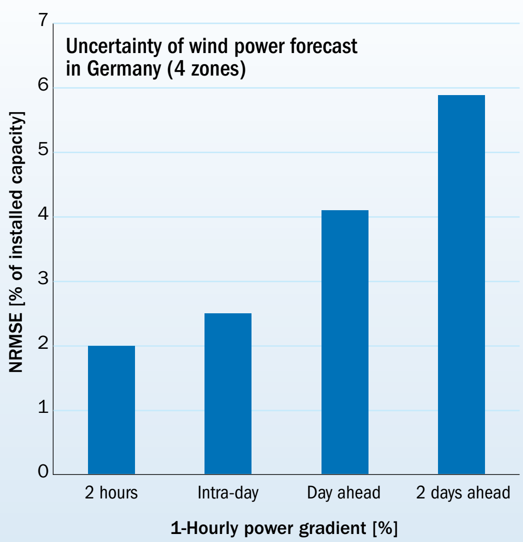
[8] The prediction error – used for measuring the accuracy of forecasting wind power – can be quantified with different error functions. The Root Mean Square Error (RMSE) method, normalised to the installed wind power, is quite common. The correlation coefficient between measured and predicted power is very useful as well. Since the penalties in case of errors often scale linearly with the error, be it up or down, the Mean Absolute Error or Mean Absolute Percentage Error (for example in Spain) is also used.

FIGURE 10: FORECAST ACCURACY IN SPAIN AS A FUNCTION OF PORTFOLIO SIZE



The aggregation of wind farms reduces the mean absolute percentage error (MAPE) from 40% to approximately 25% of deviated energy. (Source: W2M)

FIGURE 11: INCREASING AVERAGE WIND POWER FORECAST ERROR WITH INCREASING FORECAST HORIZON IN GERMANY



Data from January to December 2009 [Tambke 2010].

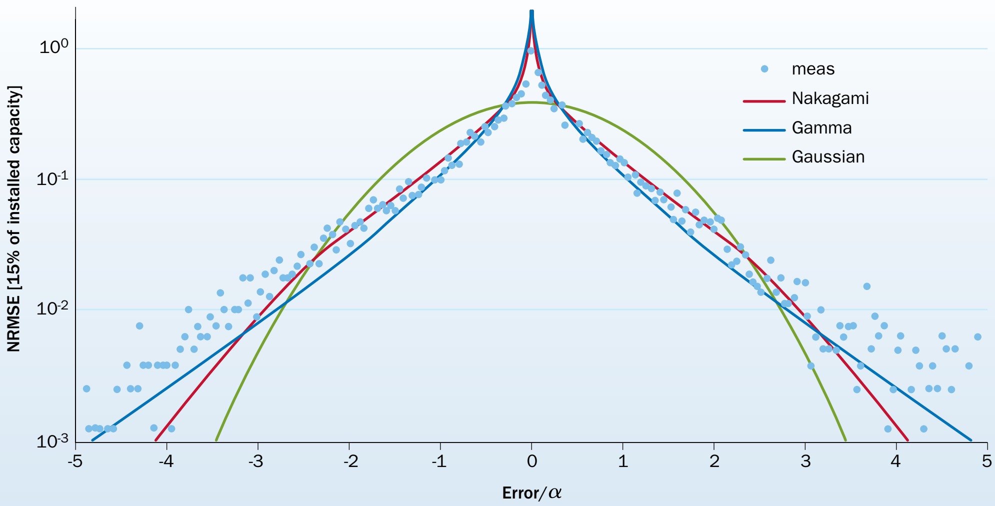
in a much more accurate prediction than using a single model.

For very short-term prediction – just two to four hours ahead, very accurate predictions are made but these need several kinds of data: a Numerical Weather Model, on-line wind power production data and real time wind measurements.

To summarise, different aspects have led to a significant improvement in short-term forecasting but, according to the experts, significant scope for further improvements remains.

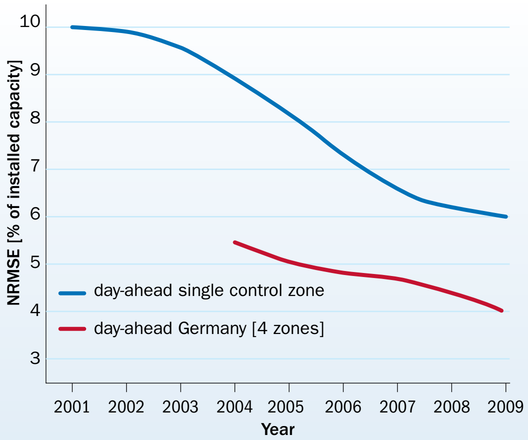
When interpreting the predictability of wind power, it is not just wind forecasting accuracy that is relevant for balancing the system. It is the total sum of all demand and supply forecast errors that is relevant for system operation. At low penetration levels, the prediction error for wind has a small effect on the total system's prediction error.

FIGURE 12: PROBABILITY DENSITY DISTRIBUTION OF ERRORS FOR DAY-AHEAD WIND POWER FORECAST FOR NORTH-WEST GERMANY; ALSO SHOWN ARE FITTED GAUSSIAN, GAMMA AND NAKAGAMI DISTRIBUTIONS



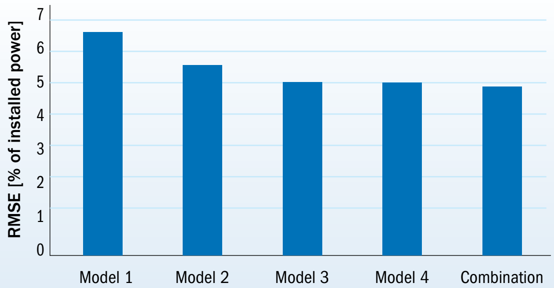
The Nakagami distribution shows the best fit for extreme forecast errors [Tambke 2010].

FIGURE 13: HISTORIC DEVELOPMENT OF THE AVERAGE FORECAST ERROR IN THE WHOLE OF GERMANY AND IN A SINGLE CONTROL ZONE IN THE LAST NINE YEARS



The improvements in accuracy are due to a combination of effects: better weather forecasts, increasing spatial distribution of installed capacity in Germany and advanced power forecast models, especially using combinations of NWPs and power forecast models [Tambke 2010].

FIGURE 14: IMPROVEMENT OF FORECAST ACCURACY BY USING ENSEMBLE PREDICTIONS



Using a combination of models results in an error 20% lower than using the most accurate of the single models [Tambke, 2008].

1.4 Impacts of large-scale wind power integration on electricity systems

The impacts of wind power on the power system can be categorised into short-term and long-term effects. The short-term effects are created by balancing the system at the operational time scale (minutes to hours). The long-term effects are related to the contribution wind power can make to the adequacy of the system, that is its capability to meet peak load situations with high reliability.

Impacts on the system are both local and system-wide

Locally, wind power plants – just like any other power station - interact with the grid voltage. Steady state voltage deviations, power quality and voltage control at or near wind power plant sites are all aspects to consider. Wind power can provide voltage control and active power control and wind power plants can reduce transmission and distribution losses when applied as distributed generation.

At system-wide scale there are other effects to consider. Wind power plants affect the voltage levels and power flows in the networks. These effects can be beneficial to the system, especially when wind power plants are located near load centres and certainly at low penetration levels. On the other hand, large-scale wind power necessitates additional upgrades in transmission and distribution grid infrastructure, just as it is the case when any power plant is connected to a grid.

In order to connect remote good wind resource sites such as offshore wind plants to the load centres, new lines have to be constructed, just as it was necessary to build pipelines for oil and gas. Combining grid access with more general electricity trade, or locating large industrial consumers close to the wind plants could compensate for the lower utilisation factor of the line due to the relatively low wind power capacity factor. In order to maximise the smoothing effects of geographically distributed wind, and to increase the level of firm power, cross border power flows reduce the challenges of managing a system with high levels of wind power. Wind power needs control regulation measures as does any other technology (see Chapter 3 on secondary and tertiary control). Moreover, depending on the penetration level and local network characteristics – wind power impacts the efficiency of other generators in the system (and vice versa).

In the absence of a sufficiently intelligent and well-managed power exchange between regions or countries, a

TABLE 6: THE IMPACTS OF WIND POWER ON THE POWER SYSTEM THAT REQUIRE INTEGRATION EFFORTS [HOLTTINEN, 2004]

	Effect or impacted element	Area	Time scale	Wind power's contribution to the system
Short-term effects	Voltage management	Local	Minutes	Wind power plants can provide (dynamic) voltage support (design dependent)
	Production efficiency of thermal and hydro	System	1-24 hours	Impact depends on how the system is operated and on the use of short-term forecasts
	Transmission and distribution efficiency	System or local	1-24 hours	Depending on penetration level, wind power plants may create additional investment costs or benefits. Wind energy can reduce network losses.
	Regulating reserves	System	Several minutes to hours	Wind power can partially contribute to primary and secondary control
	Discarded (wind) energy	System	Hours	Wind power may exceed the amount the system can absorb at very high penetrations
Long-term effects	System reliability (generation and transmission adequacy)	System	Years	Wind power can contribute (capacity credit) to power system adequacy

combination of (non-manageable) system demands and generation may result in situations where wind power has to be constrained. Finally wind power plays a role in maintaining the stability of the system and it contributes to security of supply as well as the robustness of the system. Table 6 gives an overview and categorisation of the effects of wind power on the system.

Wind power penetration determines its impact on the system

The impacts of the above described effects are very much dependent on the level of wind power penetration, the size of the grid, and the generation mix of electricity in the system. In 2010, the average energy penetration level of wind power in the EU is 5%. EWEA's target is to reach 14-17% by 2020, 26-35% by 2030 and 50% by 2050[9].

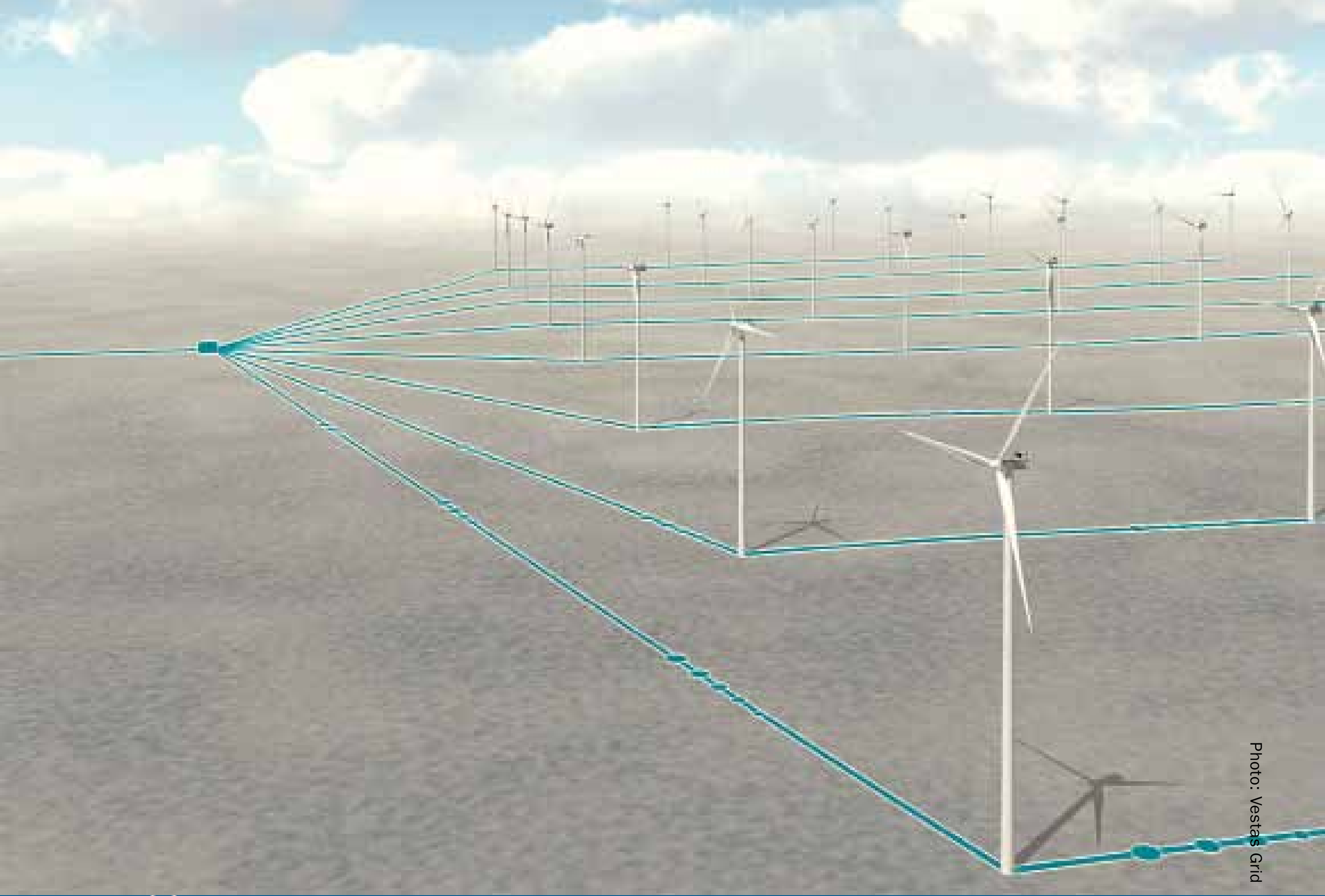
Assessing how integration costs will increase beyond this 'low to moderate' level depends on the future evolution of the power system. Costs beyond penetration levels of about 25% will depend on how underlying power system architecture changes over time as the amount of installed wind gradually increases, together with the decommissioning and construction of other generating technologies, to meet rapidly increasing demand for electricity and replacement of ageing capacity. The basic building blocks of the grid's future architecture are: a flexible generation mix, interconnection between power systems to facilitate exchanges, a more responsive demand side, possibilities to interchange with other end-uses (heat, transport) and access to storage.

Up to a penetration level of 25%, the integration costs have been analysed in detail and are consistently shown to be a minor fraction of the wholesale value of wind power generation[10]. Economic impacts and integration issues are very much dependent on the power system in question. The relevant characteristics are: the structure of the generation mix, its flexibility, the strength of the grid, the demand pattern, the power market mechanisms etc. as well as the structural and organisational aspects of the power system.

Technically, methods used by power engineers for decades can be applied to integrating wind power. But for integrating penetration levels typically higher than 25%, new power system concepts may be necessary. Such concepts should be considered from now on. Looking at experience from existing large-scale integration in numerous regions of Europe, proves that this is not merely a theoretical discussion. The feasibility of large-scale penetration is proven already in areas where wind power already meets 20%, 30% or even 40% of electricity consumption (Denmark, Ireland and regions of Germany and the Iberian Peninsula).

[9] See EWEA's report 'Pure Power: Wind energy targets for 2020 and 2030' on www.ewea.org

[10] See IEA Task 25 "Power Systems with large Amounts of Wind Power" http://www.ieawind.org/AnnexXXV.html



2 CONNECTING WIND POWER TO THE GRID

In order for the network to operate safely and efficiently, all customers connected to a public electricity network, whether generators or consumers, must comply with agreed technical requirements. Electricity networks rely on generators to provide many of the control functions, and so the technical requirements for generators are necessarily more complex than for demand customers.

These technical requirements are often termed ‘grid codes’, though the term should be used with care, as there are often different codes depending on the voltage level of connection, or the size of the project. Furthermore, there may be technical requirements which are not referred to in the grid code, but apply to the project in the connection agreement, the power purchase agreement, special incentive schemes for ancillary services (for example in Germany and Spain) or in some other way.

The purpose of these technical requirements is to define the technical characteristics and obligations of generators and the system operator. The benefits are:

- Electricity system operators can be confident that their system will be secure no matter which generation projects and technologies are installed
- The amount of project-specific technical negotiation and design is minimised
- Equipment manufacturers can design their equipment in the knowledge that the requirements are clearly defined and will not change without warning or consultation
- Project developers have a wider range of equipment suppliers to choose from
- Equivalent projects are treated equitably
- Different generator technologies are treated equally, as far as is possible

2.1 Problems with grid code requirements for wind power

In the past, with vertically-integrated utilities, the same organisation was responsible for the planning and operation of networks and giving access to generators, and therefore the technical requirements did not have to be particularly clearly defined or equitable. Now, with legal and increased ownership separation due to new EU legislation, most prominently the third liberalisation package between generators and network owners/operators, the technical requirements governing the relationship between generators and system operators must be more clearly defined[11]. The introduction of renewable generation has often complicated this process significantly, as these generators have characteristics which are different from the directly connected synchronous generators used in large conventional power plants. In some countries, this problem has introduced significant delays in the formation of grid code requirements for wind generation.

A specific problem today is the diversity of national codes and requirements. Another concern for the industry is the fact that requirements are not formulated precisely enough, leaving room for varying interpretations and lengthy discussions between concerned parties.

In some countries, a grid code has been produced specifically for wind power plants. In others, the aim has been to define the requirements as far as possible in a way which is independent of the generator technology. There are benefits in producing requirements which are as general as possible, and ones which treat all projects equally. However this can result in small projects facing the same requirements as the largest projects, which may not be technically justified or economically optimal. The European Wind Energy Association (EWEA) advocates a Europe-wide harmonisation of requirements, with a code specifically formulated for wind power.

Some diversity may be justified because different systems may have different technical requirements due to differences in power mix, interconnection to neighbouring countries and size. However, each country across the globe uses the same constant voltage and constant synchronous frequency system – it is only the physical parameters which are different. Grid code documents from the different EU countries are not at all homogeneous. Additionally, documents are often not available in English making them inaccessible[12]. These issues create unnecessary extra costs and require additional efforts from wind turbine designers, manufacturers, developers and operators.

Requirements for the dimensioning, capabilities and behaviour of wind power plants are often not clear, and are not always technically justified or economically sound from the point of view of the system and the consumer.

Historically, requirements have usually been written by the system operator at national level, while the energy regulatory body or government has an overview. However, in the interests of fairness and efficiency, the process for modifying requirements should be transparent, and should include consultations with generators, system users, equipment suppliers and other concerned parties. The process should also leave sufficient time for implementing modifications. The regulatory process initiated at European level to develop the first European network code on grid connection by ENTSO-E creates an opportunity for the wind power industry to get thoroughly involved.

The wind turbines that are currently available do not yet make full use of all possible control capabilities, for reasons of cost and also because grid codes do not yet take advantage of the full capabilities they could provide. As wind penetration increases, and as network operators gain experience with the new behaviour of their systems, grid codes may become more demanding. However, new technical requirements should be based on an assessment of need, and on the best way to meet that need.

[11] Directive 2009/72 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.

[12] There is no one stop shop that provides grid codes from different countries. A fairly complete list of national codes can be obtained here: http://www.gl-group.com/pdf/IGCC_list.pdf

2.2 An overview of the present grid code requirements for wind power

Essential requirements

Technical grid code requirements and related documents vary from one electricity system to another. However, for simplicity, the typical requirements for generators can be grouped as follows:

- Tolerance - that is, the range of conditions on the electricity system for which wind power plants must continue to operate
- Control of reactive power: this often includes requirements to contribute to the control of voltage in the network
- Control of active power and frequency response
- Protective devices
- Power quality
- Visibility of the power plant in the network

It is important to note that these requirements are often specified at the Point of Connection (POC) of the wind power plant to the electricity network. In this case, the requirements are placed on the wind power plant. To achieve them the requirements for wind turbines may have to be different. Often wind turbine manufacturers will only specify the performance of their wind turbines, not the entire wind power plant. EWEA recommends that for transparency and inter-comparability, all grid codes should specify the requirements to apply at POC. It is also possible to meet some of the requirements by providing additional equipment separate from wind turbines. This is noted below where relevant.

Tolerance

The wind power plant must continue to operate between minimum and maximum limits of *voltage*. Usually this is stated as steady-state quantities, though a wider range may apply for a limited duration.

The wind power plant must also continue to operate between minimum and maximum limits of *frequency*. Usually there is a range which is continuously applied, and several further more extreme short-term ranges. Early generation wind turbines (type A)[13] are generally not capable of meeting wider operational frequency ranges as stipulated in several grid codes. However, the operation of a wind turbine in a wider frequency range is not really a complicated task as it mainly involves the thermal overloading of equipment, which has short thermal time-constants, in particular by using power electronic components. A possible solution for short-term overload capability consists of oversizing the converters, which in general can be done at reasonable cost. Increased operating temperature may also result in a reduced insulation lifetime. However, since operation at deviating frequency occurs rarely, the effect is negligible and can be reduced by limiting power output at the extremities of the frequency range. Therefore – in general - wind turbines can be made to operate in wider frequency ranges.

In systems with relatively high wind penetration, it is common that wind power plants are required to continue to operate during severe system disturbances, during which the voltage can drop to very low levels for very short periods. This is termed fault ride-through (FRT) or low voltage ride-through. A decade back, the TSOs required all wind turbines to disconnect during faults. Today they demand that wind turbines stay on the grid through these disturbances. Faults are inevitable on any electrical system and can be due to natural causes (e.g. lightning), equipment failure or third party damage. With relatively low transmission circuit impedances, such fault conditions can cause a large transient voltage depression across wide network areas. Conventional large synchronous generators are – in general - expected to trip only if a permanent fault occurs in the circuit to which they are directly connected[14]. Other generators that are connected to adjacent healthy circuits should remain connected and stable after the faulty circuits are disconnected, otherwise too much generation will be lost in addition to that

[13] Wind turbine electrical concept types as previously defined.

[14] The actual fulfilment of the FRT requirement is not always the case with large conventional generators such as some new CCGT's in Europe and nuclear power plants in the USA.

disconnected by the original fault. Clearly, in this case the power system would be exposed to a loss of generation greater than the current maximum loss it is designed for, with the consequent danger of the system frequency dropping too rapidly and load shedding becoming necessary.

The requirements can be complex, and depend on the characteristics of the electricity system. Complying with the requirements may not be easy. It is feasible to use wind turbines which do not themselves comply with the FRT requirements, and meet the FRT requirements by installing additional equipment at the turbines or centrally within the wind power plant which can produce or consume reactive power.

Reactive power and power factor control

Reactive power production and consumption by generators allows the network operator to control voltages throughout their system. The requirements can be stated in a number of ways.

The simplest is *fixed power factor*. The wind power plant is required to operate at a fixed power factor when generating, often this is 1.0. Often the required accuracy is not stated. The fixed value may be changed occasionally, for example during winter and summer.

Alternatively, the wind power plant can be asked to adjust its reactive power consumption or production in order to control the voltage to a set point. This is usually the voltage at the POC, but other locations may be specified. There may be requirements on the accuracy of control, and on the speed of response. Fast control may be difficult to achieve, depending on the capabilities of the wind power plant SCADA communications system.

Some wind turbine designs are able to provide these functions even when the wind turbine is not generating. This is potentially a very useful function for network operators, but it is not yet a common requirement.

When considering FRT, it is also possible to meet these requirements with central reactive power compensation equipment.

Active power control and frequency response

The system operator may add requirements to the code governing the extent to which the generator is capable of actively adjusting the output power. In addition he may require the generator to respond to grid frequency deviations.

For any generator, the ability to control frequency requires controlling a prime mover. Although the wind speed cannot be controlled, the power output of a wind turbine can be controlled by most modern turbines. With pitch-regulated turbines, it is possible to reduce the output at any moment by pitching the blades. In principle, it is also possible to do this with stall-regulated turbines by shutting down individual turbines within a wind power plant, but this only provides relatively crude control.

The simplest, but most expensive, method is a cap. In this case the wind power plant (or a group of wind plants) is instructed to keep its output below a certain level. A more complex version of the cap is to require output to be kept to a fixed amount (delta) below the unconstrained output available from the wind.

In parallel with a cap, the wind power plant may also be instructed to control ramp rate, i.e. to limit the rate at which the output power can increase (due to increasing wind speed, or due to turbines returning to service after some outage). The ramp rate is defined over periods of, for example, one minute or 10 minutes. This limits the demands the network operator has to make on other forms of generation to change their output rapidly.

Clearly it is not possible for the wind generation to control negative ramp rate at will, if the wind drops suddenly. However, with good wind forecasting tools, it is possible to predict a reduction in wind speed. Wind generation output can then be gradually reduced in advance of the wind speed reduction, thereby limiting the negative ramp rate to an acceptable level.

The ability of generators to increase power output in order to support system frequency during an unexpected increase in demand escalation or after a loss of a network element is important for system operation. Therefore, on systems with relatively high wind penetration, there is often a requirement for frequency response or frequency control. Pitch controlled wind turbines are capable of such system support only when they are set in advance at a level below the rated output and, of course, if wind is available. This allows them to provide primary and secondary frequency control. This can take many forms, but the basic principle is that, when instructed, the wind power plant reduces its output power by a few percent, and then adjusts its output power in response to the system frequency. By increasing power when frequency is low or decreasing when frequency is high, the wind power plant provides a contribution to controlling the system frequency.

The problem associated with this type of network assistance from wind turbines is a reduced output and hence loss of income, which might not be offset by the primary control service. This is less of an issue for conventional power stations, where the lost revenue will be compensated to some extent by a reduction in fuel consumption. For wind power this implies a loss of electricity produced at zero fuel costs, therefore it is not the cheapest option for the system, and should only be applied when other more cost effective options, such as fuel based technology curtailments, have been exhausted.

Protective devices

Protective devices such as relays, fuses and circuit breakers are required in order to protect the wind power plant and the network from electrical faults. Careful co-ordination may be required, in order to ensure that all conceivable faults are dealt with safely and with the minimum disconnection of non-faulty equipment. *Fault current* is a related issue. In the event of an electrical fault in the network close to the wind power plant, some fault current will flow from the wind turbines into the fault. There may be requirements on the maximum or minimum permitted levels.

Power quality

This term covers several separate issues [IEC, 2008] that determine the impact of wind turbines on the voltage quality of an electric power network. It applies in principle both to transmission and distribution networks, but is far more essential for the latter which are more susceptible to voltage fluctuations on the generation side.

The relevant parameters are active and reactive power, including maximum value, voltage fluctuations (flicker), number of switching operations (and resulting voltage variations), harmonic currents and related quantities. The standard for characterising the power quality of wind turbines and for the measurement of the related quantities is IEC 61400-21 [IEC, 2008]. The application of this standard enables a careful evaluation of the impact of wind power plants on the voltage quality in electrical networks. Instead of applying simplified rules which would be prohibitive for wind power, analysis of IEC 61400-21 methods is recommended (Tande in [Ackermann 2005] p.79) in order to carry out the following:

- Load flow analysis to assess whether slow voltage variations remain within acceptable limits
- Measurements and comparison with applicable limits of maximum flicker emission which can be caused by wind turbines starting or stopping, or in continuous operation
- Assessment of possible voltage dips due to wind turbine start-up, stops or by energisation of transformers
- Estimation of maximum harmonic current and comparison with applicable limits

Visibility

In a power system with large contributions from decentralised plants, it is essential for the system operator to obtain on-line information about the actual operational conditions at the decentralised plants. Access to such information can, for example, be critical during network faults when fast decisions have to be made to reschedule generators and switch network elements. For this purpose, agreements are made between the system operator and the wind plant operators on communicating signals such as active and reactive power, technical availability and other relevant status signals. On-line information about wind plants can also be necessary for system operation for the purpose of short-term forecasting of the output of wind plants in a region.

Future developments

As noted above, technical requirements may well become more onerous for wind generation as wind power penetration levels increase in the future.

One possible new requirement is for an *inertia* function. The spinning inertias in conventional power plants provide considerable benefits to the power system by acting as a flywheel, and thereby reducing the short-term effects of imbalances of supply and demand. Variable speed wind turbines have no such equivalent effect, but in principle their control systems could provide a function which mimics the effect of inertia.

There may also be a move towards *markets for services*, rather than mandatory requirements. This would be economically more efficient, as the generator best able to provide the service will be contracted to provide it. For example, if a wind power plant provides a useful service to the network operator in controlling voltages, i.e. it does more than just correct its own negative effects, then the wind power plant should be paid for this service. Whether this is cheaper than other options available to the network operator should be determined by the market. Moreover, due to the power electronics in electrical conversion systems, wind power plants can provide some network services, especially voltage control, more rapidly than conventional thermal plants.

2.3 Two-step process for grid code harmonisation in Europe

There is considerable potential for improving the process of wind power integration by harmonising grid codes requirements for wind power. Such a process will benefit all the stakeholders involved in the integration of wind power. A systematic approach to setting a European grid code harmonisation process in motion was proposed by EWEA in 2008[15]. Harmonisation does not automatically mean that the maximum and most stringent requirements should apply everywhere, rather it is a process of cleaning out technically unjustified requirements and creating a transparent, understandable, comprehensive and well-defined set of requirements according to common definitions and specifications and optimised to the power systems where they apply.

A two-step harmonisation strategy introduced by EWEA consists firstly of a *structural* harmonisation, and secondly a *technical* harmonisation. Together, the two forms of harmonisation should particularly benefit those system operators that have not yet developed their own customised grid code requirements for wind-powered plants.

Structural harmonisation consists of establishing a grid code template with a fixed and common structure (sequence and chapters), designations, definitions, parameters and units. The key aim of the structural harmonisation process is to establish an accepted framework for an efficient grid code layout. Such a template was launched[16] by EWEA in 2009.

Technical harmonisation can be seen as a more long-term process which works by adapting existing grid code parameters following the template of the aforementioned new grid code. The process is to be implemented through co-operation between TSOs (ENTSO-E), the wind power industry and regulatory bodies (ACER). The implementation of the Third Liberalisation package as described below provides the proper enabling legal and institutional framework at EU level.

European developments a towards European code

In the developing European internal electricity market, national networks have to be interlinked in a more efficient way. They must be operated as part of an integrated European grid to enable the necessary cross border exchanges. This requires harmonised codes and technical standards, including grid connection requirements. However, the national power systems in Europe today are so different that a full harmonisation cannot and should not be carried out straight away.

[15] http://www.ewea.org/fileadmin/ewea_documents/documents/publications/position_papers/ 080307_WGGCR_final.pdf
[16] http://www.ewea.org/fileadmin/ewea_documents/documents/publications/091127_GGCF_ Final _Draft.pdf

The implementation of further liberalisation measures in the energy sector in Europe, as imposed by the so-called Third Liberalisation Package, involves the creation of a European network code for connection. This process involves several steps in which European TSOs and European regulators play a crucial role. Basically, the regulators (ACER) set out the framework for the code in a so-called framework guideline. Consequently, the TSOs draft the European code according to the terms set out in the framework guideline. Once established, the code will be imposed throughout European and national legislation (comitology). The process asks for an open consultation with the relevant industry associations when drafting the codes. With this, the legal framework has been set for further developing harmonised grid code requirements through co-operation between TSOs and the wind energy sector. At the same time, this creates the opportunity to strike a proper balance between requirements at wind plant and at network level, in order to ensure the most efficient and economically sound connection solutions. EWEA recommends that in this future European code for network connection, there is a clear grouping of wind power related grid code requirements in a separate chapter to ensure the maximum level of clarity and an adequate valuation of the specific power plant capabilities of wind power.

Photo: REpower

3 SUMMARY

State-of-the-art wind power technology with advanced control features is designed to enhance grid performance by providing ancillary services. Using these power plant characteristics to their full potential with a minimum of curtailment of wind power is essential for efficiently integrating high levels of wind power. Advanced grid-friendly wind plants can provide voltage control, active power control and fault-ride-through capability. Emulating system inertia will become possible too. The economic value of these properties in the system should be reflected in the pricing in proportion to their cost.

Wind power provides variable generation with predictable variability that extends over different time scales (seconds, minutes, hours and seasons) which are relevant for system planning and scheduling. The intra-hour variations are relevant for regulating reserves; the hour by hour variations are relevant for load following reserves. Very fast fluctuations on second to minute scale visible at wind turbine level disappear when aggregated over wind farms and regions. The remaining variability is significantly reduced by aggregating wind power over geographically dispersed sites and large areas. Electricity networks provide the key to reduction of variability by enabling aggregation of wind plant output from dispersed locations. Wind plant control can help control variability on a short time scale.

The latest methods for wind power forecasting help to predict the variations in the time scale relevant for system operation with quantifiable accuracy. Aggregating wind power over large areas and dispersed sites and using combined predictions helps to bring down the wind power forecast error to manageable levels in the time frames relevant for system operation (four to 24 hours ahead). Furthermore, well interconnected electricity networks bring many advantages. In order to control the possible large incidental forecast errors, reserve scheduling should be done in as short as possible time frames (short gate-closure times), assisted by real time data on wind power production and site specific wind conditions. The significant economic benefits of improved accuracy justify investment in large meteorological observational networks.

The way grid code requirements in Europe have been developed historically has resulted in gross inefficiencies for manufacturers and developers. As the amount of wind power in the system continues to grow in Europe, there is an increasing need to develop a harmonised set of grid code requirements. Harmonised technical requirements will maximise efficiency for all parties and should be employed wherever possible and appropriate. However, it must be noted that it is not practical to completely harmonise technical requirements straight away. In an extreme case this could lead to the implementation of the most stringent requirements from each Member State. This would not be desirable, economically sound, or efficient.

EWEA proposes a two step harmonisation approach for grid codes, namely a structural harmonisation followed by a technical harmonisation. The proposed harmonising strategies are urgently needed in view of the significant increase in foreseen wind power penetration and should be of particular benefit to:

- Manufacturers, who will now be required only to develop common hardware and software platforms
- Developers, who will benefit from the reduced costs
- System operators, especially those who have yet to develop their own grid code requirements for wind powered plants

The technical basis for the requirements should be further developed in work carried out jointly between TSOs and the wind power industry in studies at European and international level. If the proposals can be introduced at European level by means of a concise network code on grid connection, it will set a strong precedent for the rest of the world.

3 POWER SYSTEM OPERATIONS WITH LARGE AMOUNTS OF WIND POWER

1 INTRODUCTION

While today's power systems are able to integrate ever growing amounts of wind energy, an innovative approach to expanding and running the systems is necessary, especially at higher penetration levels. Many of the studies mentioned in this chapter have concluded that it is possible to efficiently integrate large amounts of wind power (20% and up) when the power system is being developed in an evolutionary way. Many factors can help with this, and this chapter of the report attempts to address the major ones. It shows which changes are necessary to the way various parts of the power system (generation, network and demand side) are operated. As a major principle, in order to efficiently integrate a large amount of variable renewable generation like wind power, the system should be designed with a higher degree of flexibility through a combination of flexible generating units, flexibility on the demand side, availability of interconnection capacity and a set of power market rules that enable a cost-effective use of the flexibility resources.


Photo: Thinkstock

2 BALANCING DEMAND, CONVENTIONAL GENERATION AND WIND POWER

2.1 Introduction

Just like with any other major power source, when significant amounts of new wind generation are integrated in an economic and orderly way into the power supply, (relative) extra reserve power is required, the power cost changes, technical measures must be taken and the power market redesigned.

It is important to note that system balancing requirements are not assigned to back up a particular plant type (e.g. wind), but to deal with the overall uncertainty in the balance between demand and generation. Moreover, the uncertainty to be managed in system operation is driven by the combined effect of the fluctuations both (i) in demand, and (ii) in generation from conventional *and* renewable generation. These individual fluctuations are generally not correlated, which has an overall smoothing effect and consequently, a beneficial impact on system integration cost.

System operators' operational routines vary according to the synchronous systems and the countries they are in. The terminology of the reserves used also varies. In this document, we put the reserves into two groups according to the time scale they work in: primary reserve for all reserves operating in the second/minute time scale and secondary/tertiary reserve for all reserves operating in the 10 minute/hour time scale. Primary reserve is also called instantaneous, frequency response, or automatic reserve or regulation. Secondary reserve is also called fast reserve and tertiary reserve is also called long-term reserve (the term 'load following reserve' is also used for the latter two). The principles of how the power system is operated are explained in the Annex.

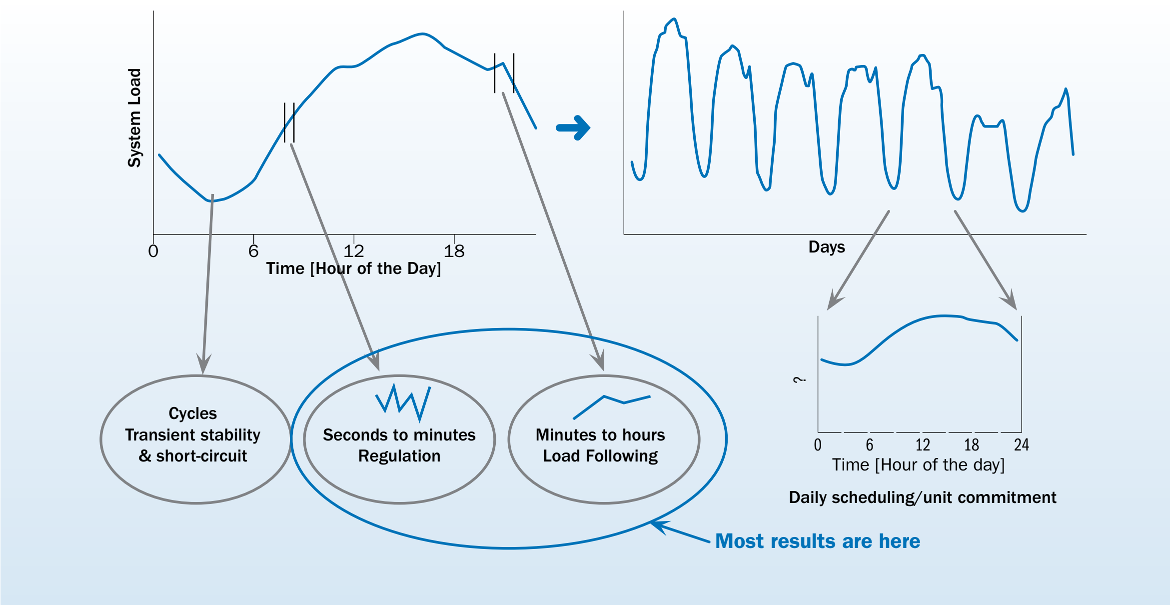
Wind power's impacts on power system balancing can be seen over several time scales, from minutes to hours, up to the day-ahead time scale. It can be seen both from experience and from tests carried out that the variability of wind power from one to six hours poses the most significant requirements to system balancing, because of the magnitude of the variability and limitations in forecast systems. At present, frequency control (time scale of seconds) and inertial response are not crucial problems when integrating wind power into large interconnected power systems. They can however be a challenge for small systems and will become more of a challenge for systems with high penetration in the future.

2.2 Effect of wind power on scheduling of reserves

The amount of additional reserve capacity and the corresponding costs when increasing the penetration of wind power are being explored by power engineers in many countries. The investigations simulate system operation and analyse the effect of an increasing amount of wind power for different types of generation mix. The increase in short term reserve requirement is mostly estimated by statistical methods that combine the variability or forecast errors of wind power to that of load and investigates the increase in the largest variations seen by the system. General conclusions on increasing the balancing requirement will depend on factors such as the region size, initial load variations and how concentrated/distributed wind power is sited.

In 2006 an agreement on international cooperation was set up under the IEA Task 25[1] to compare and analyse the outcome of different national power system studies. The 2009 report of this Task 25 [Holttinen, 2009] gives generalised conclusions based on studies from Denmark, Finland, Norway, Sweden, Germany, Ireland, Spain, Netherlands, Portugal, the UK and the USA. This experience is used in this report to illustrate the issues and solutions surrounding the reserves question. The value of the combined assessment in the IEA Task 25 is that it allows the systematic relationship of the increased demand of system reserves to be shown as a function of wind energy penetration.

FIGURE 1: TIMESCALES FOR UTILITY OPERATIONS [PARSONS, 2003]



[1] http://www.ieawind.org/AnnexXXV.html

When considering the impacts of wind power on the different types of reserve requirements, it is of central importance to make a clear distinction between the need for flexibility *in longer time scales of several hours to a day* (power plants that can follow net load variation) and the need for reserves that can be activated *in seconds or minutes* (power plants that can follow unpredicted net load variations – demand minus wind). Figure 1 illustrates the time scales of relevance.

Primary reserves

Wind power development will have only a small influence on the amount of primary reserves needed. On time scales of seconds/minutes, rapid variations in total wind power capacity output occur randomly, like the load variations that already exist. When aggregated with load and generation variations, the increase in variability due to wind is very small. Furthermore, the amount of primary reserve allocated to the power systems is dominated by the potential outages of large thermal generation plants, so it is more than large enough to cope with the very rapid variations in wind. In practice, power plant generation is scheduled to match the anticipated trends in demand so it can be balanced with the supply. For any deviations from the anticipated trends, primary and secondary reserves are operated continuously to keep system frequency close to its nominal value (see page 83). In addition, wind power can provide its own primary reserve.

Secondary and tertiary reserves

On the time scale of 10-30 minutes the impact of wind power on the need for secondary reserves will only be significant and increase due to wind energy penetration levels of more than 10%[2].

Wind power has a much more significant impact on the way conventional units are scheduled to follow the load (hour to day time-scales). In the absence of a perfect forecast, the *unit-commitment* decision will be surrounded by uncertainty additional to the normal uncertainty associated with load and conventional generation outage forecasting. The result is that sometimes a unit might be committed when it is not needed, and sometimes a unit might not be committed when it is needed. Here, the generation mix of the power system determines how the scheduling will change according to the expected wind power production – the more flexible power units there are, the later the unit commitment decisions need to be made.

Estimates for the increase in short-term reserve balancing capacities [Holttinen, 2009] show a wide range: 1-15% of installed wind power capacity at 10% penetration (of gross demand) and 4-18% of installed wind power capacity at 20% penetration.

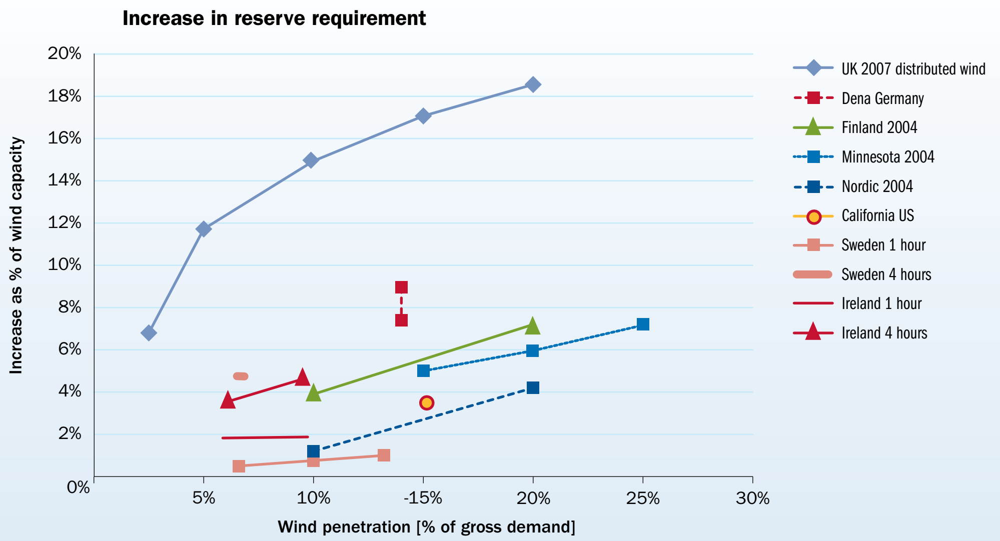
Discussion of additional reserve requirements

Differences in the power system's operational routines explain a lot of the differences shown in Figure 2, notably how often the forecasts of load and wind are updated. If a re-dispatch based on a forecast update is done in four to six hours, this would lower the reserve requirements and costs of integrating wind compared with scheduling based on only day-ahead forecasts. Emerging *intra-day markets* take this particularity into account by giving the opportunity for hourly updates. The way the power system is operated regarding the time lapse between forecast schedules and delivery has a decisive impact on the degree of uncertainty wind power will bring and so will indirectly determine the amount of additional reserves required.

It is important to note that an increase in reserve requirements does not necessarily mean new investments will have to be made, for example the construction of new thermal power plants. From analysis of the system and from experience it follows that the forecast uncertainty of incidental combinations of wind power generation and demand is critical for assessing the need for additional reserves, especially the "low demand high wind"

[2] See IEA Task 25 "Power Systems with large Amounts of Wind Power" http://www.ieawind.org/AnnexXXV.html

FIGURE 2: ESTIMATES OF THE INCREASE IN RESERVE CAPACITY REQUIREMENT DUE TO WIND POWER



The Dena study takes into account the day-ahead uncertainty (for up and down reserves separately), whereas the UK study takes into account the variability of wind four hours ahead. In Minnesota and California, day-ahead uncertainty has been included in the estimate. For the others the effect of variations during the operating hour is considered. For Ireland and Sweden the four hour ahead uncertainty has been evaluated separately [Holttinen, 2009].

combination. Additional flexibility from conventional units is especially critical in situations of low load and high wind [Ummels, 2008] because in such situations the thermal plant may have to be ramped up fast because of sudden drops in wind power generation. More generally, increased wind power will mean conventional thermal units will have to be operated in a more flexible manner than if there were no wind energy.

2.3 Short-term forecasting to support system balancing

Wind power forecasting has become essential for operating systems with a significant share of wind power. Forecast systems are used by various parties, including network operators, energy traders and wind plant operators. The main benefits are reduced costs and improved system security. Forecasting enables wind power to be traded and integrated in the scheduling system, which eventually ensures that demand and power supply are balanced and makes use of the most cost-effective generation sources.

In regions with a high level of penetration – which include regions in Spain, Germany, Denmark and Ireland – wind farm operators routinely forecast output from their wind farms. These forecasts are used by system operators to schedule the operations of other plants, and for trading purposes. Areas of power system operation where system operators specifically benefit from wind power forecasts include:

- Routine forecasts: increasing the confidence levels
- Forecasting in critical periods, e.g. times of maximum load (including ramps)
- Forecasting of significant aggregated wind power fluctuations (ramps)
- Severe weather forecasts

Forecasting has a potentially high economic value to the system, especially with large amounts of wind

TABLE 1: CLASSIFICATION OF WIND POWER FORECAST METHODS ACCORDING TO TIME SCALES RELEVANT FOR POWER SYSTEM OPERATION

	5-60 min	1-6 hours	Day-ahead	Seasonal long-term
Uses	Regulation Real-time dispatch decisions	Load following, unit commitment for next operating hour	Unit commitment and scheduling, market trading	Resource planning contingency analysis
Phenomena	Large eddies, turbulent mixing transitions	Fronts, sea breezes, mountain-valley circulations	Low and high pressure areas, storm systems	Climate oscillations, global warming
Methods	Largely statistical, driven by recent measurements	Combination of statistical and NWP models	Mainly NWP with corrections for systematic bias	Based largely on analysis of cyclical patterns

power. A study from the US (California) [GE/AWST 2007] has quantified the cost-benefit ratio to be 1:100. Large additional investments are required to effectively implement centralised forecast systems, especially investments in observation networks in order to provide the necessary meteorological and operational data. Such investments are justified by the significant reductions they entail to the operational costs of power generation.

Time horizons for the relevant system operation actions are listed in Table 1. There are distinct predictable meteorological phenomena linked to each horizon. Professional forecast providers adjust prediction methods to these phenomena.

The nature of the wind power forecast error statistics leads to the following important observation: the total amount of balancing *energy* stems from the *average* forecast error; however, the need for reserve *power* is dependent mainly on the *extreme* forecast error. Therefore, apart from using the best available forecasts, the method recommended for reducing the required balancing power (and thus reserve plant capacity) is to keep the forecast error as low as possible by intra-day trading in combination with very short-term forecasting (2-4 hours ahead) [Lange, 2009].

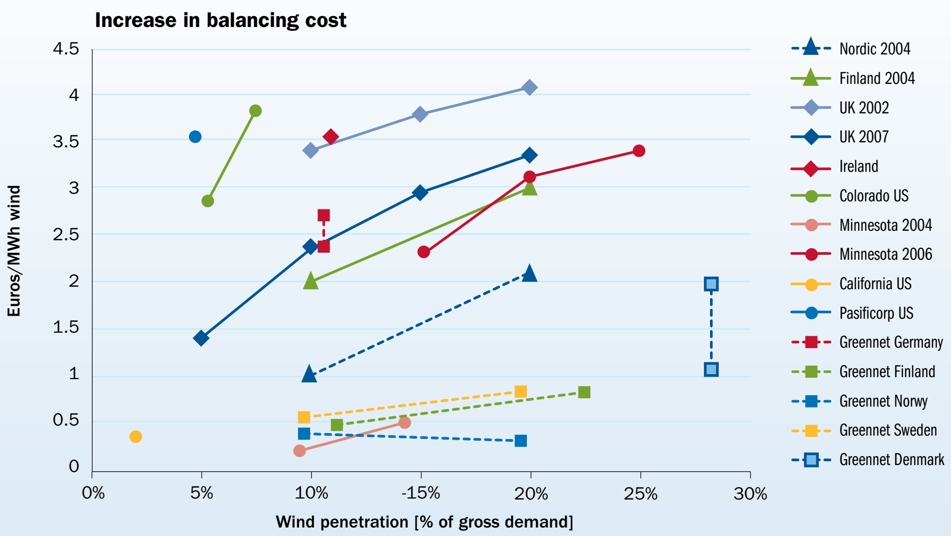
2.4 Additional balancing costs

The overview of studies investigating wind penetrations of up to 20% of gross demand (energy) in national or regional power systems [Holttinen, 2009], already mentioned in Chapter 2 concludes that increases in system operating costs arising from wind variability and uncertainty amount to about €1-4/MWh wind energy produced. This cost is normalised per MWh of wind energy produced and refers to the wholesale price of electricity in most markets.

The studies calculate the additional costs of adding different amounts of wind power as compared to a situation without any. The costs of variability are also addressed by comparing simulations assuming constant (flat) wind energy to simulations with varying wind energy.

Both the allocation and the use of reserves create additional costs. As mentioned in Chapter 2, the consensus from most studies made so far is that for wind energy penetration levels up to 20%, the extra reserve requirements needed for larger amounts of wind power is already available from conventional power plants in the system. That is, no new reserves would be required, and thus additional investments in new plants wouldn't be necessary. Only the increased use of dedicated reserves, or increased part-load plant requirement, will cause extra costs (energy part) – and there is also an additional investment cost related to the additional flexibility required from conventional plants. The costs themselves depend on the marginal costs for providing regulation or mitigation methods used in the power system as well as on the power market rules.

FIGURE 3: BALANCING AND OPERATING COSTS DUE TO WIND POWER AS FUNCTION OF WIND ENERGY PENETRATION



For the UK's 2007 study, the average cost is presented here, the range in the last point for 20% penetration level is from €2.6 to 4.7/MWh (IEA Task 25 final report)[3].

The main contributing factors to lower balancing costs are:

- **Larger areas:** Large balancing areas offer the benefits of lower variability. They also help decrease the amount of forecast errors in wind power forecasts, and thus reduce the amount of unforeseen imbalance. Large areas favour the pooling of more cost-effective balancing resources. In this respect, the regional aggregation of power markets in Europe is expected to improve the economics of wind energy integration. Additional and better interconnection is the key to enlarging balancing areas. Certainly, improved interconnection will bring benefits for wind power integration, as explained in Chapter 2.
- **Reducing gate-closure times:** This means operating the power system close to the delivery hour. For example, a re-dispatch, based on a 4–6 hour forecast update, would lower the costs of integrating wind power, compared to scheduling based on only day-ahead forecasts. In this respect the emergence of intra-day markets will facilitate larger amounts of wind energy in the system – see Chapter 4.
- **Improving the efficiency of the forecast systems:** Balancing costs would be decreased if wind power forecast accuracy was improved, leaving only small deviations in the rest of the power system. Experience from different countries (Germany, Spain and Ireland), shows that the accuracy of the forecast has been improved in several ways, ranging from improvements in meteorological data supply to the use of ensemble predictions and combined forecasting. In the latter two, the quality of the forecast is improved by making a balanced combination of different data sources and methods in the prediction process (see also Chapter 2, section 1).

[3] The currency conversion: €1 = £0.7 and €1 = US$1.3

3 IMPROVED WIND POWER MANAGEMENT

To enable a power system to integrate large amounts of wind power, optimised wind power operation, management and control are necessary.

The pooling of several wind farms into clusters in the GW range will make new options feasible for an optimised integration of variable generation into electricity supply systems. New concepts for cluster management will include the aggregation of geographically dispersed wind farms according to various criteria, for the purpose of an optimised network management and optimised (conventional) generation scheduling. The clusters will be operated and controlled like large conventional power plants.

In view of the probable wind power forecast errors, the difference between forecast and actual supply must be minimised by means of control strategies of wind farm clusters to ensure the generation schedule is maintained. Power output will in this case be controlled in accordance with the schedule determined by the short-term forecasts. This strategy has a large impact on the operation of the wind farms and requires announced and actual generation to be matched on a minute-to-minute basis. The schedule should be carried out within a certain tolerance band (which should itself be determined by forecast error). Time-variable set points should be constantly generated and refreshed for optimum interaction between wind farms and wind farm cluster management. It is assumed that short-term forecasting for wind farms and cluster regions is used and continually updated for this kind of operation management. Wind farm control strategies include:

- Limitation of power output
- Energy control

- Capacity control
- Minimisation of ramp rates

Non-controllable wind farms can be supported by controllable ones in a particular cluster. This strategy will allow hybrid clusters to fulfil their requirements.

Contribution of wind power in congestion management

From time to time wind power generation achieves, and can exceed, the maximum temperature allowed of grid components. The situations can be foreseen and avoided by network simulations based on wind generation forecasting and the limitation of wind power output to a pre-calculated threshold. Different wind farms in a cluster can be curtailed differently, thus giving an opportunity for an economical optimisation of the process.

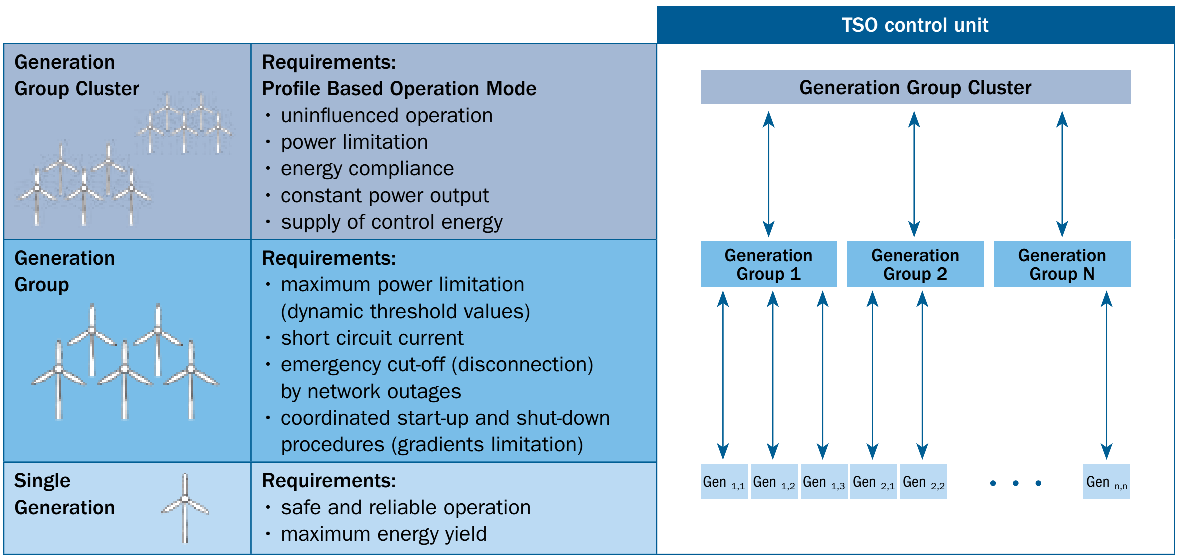
Losses reduction, optimisation of active and reactive power flows

Wind power generation is variable not only over time, but also geographically, and geographical variations can lead to power flows over large distances and associated power losses. Such situations can be identified beforehand and reduced or even completely prevented by the interaction of wind clusters with conventional power plants. The transmission of reactive power can be managed in a similar way.

Implementation of these operating methods will significantly increase wind energy's economic value to the system by keeping the additional balancing costs to a minimum. Based on innovative wind farm operational control, a control unit between system operators and wind farm clusters, wind farm cluster management will enable profile based generation (i.e. the output of a generation cluster following a certain time schedule facilitating system operation) and management of the following tasks:

- taking account of data from online acquisition and prediction
- aggregation and distribution of predicted power generation to different clusters
- consideration of network restrictions arising from network topology
- consideration of restrictions arising from power plant scheduling and electricity trading
- scaling of threshold values
- allocation of target values to different clusters and generation plants

FIGURE 4: WIND FARM CLUSTER MANAGEMENT SYSTEM [ISET, 2005]



The combination and adjustment of advanced wind farm control systems for cluster management will be achieved by the wind farms cluster management. Furthermore, the cluster management prepares and administrates profiles for the plant control systems based on forecasts, operating data, online-acquired power output and defaults from the system operators.

Control centres - CECRE: Control Centre For Renewable Energies

Spanish power transmission company Red Eléctrica is a pioneer in renewable energy resource control. Its Control Centre for Renewable Energies (CECRE) is a model of how to maximise renewable energy production. CECRE allows renewable energy to be integrated into the national power system under secure conditions. As an operational unit integrated into the overall power control centre in Madrid, CECRE manages and controls the output of renewable energy producers, anticipating sudden losses in power generation. With CECRE, Spain is the first country to have a control centre for all its wind farms over 10 MW.

- CECRE is an operation unit integrated into the Electrical Control Centre (CECOEL). The generation of RES producers in Spain are managed and controlled by CECRE.

- In addition this centre is the sole interlocutor in real time between CECOEL and each of the authorised generation control centres to which the wind farms are connected.

- Its main function is to supervise and control renewable energy generation, mainly wind power. It also articulates the integration of its production to the power system in a way compatible with its security. Therefore:
  - Information is collected from the production units, which in turn is needed for real time operation. Measurements such as active and reactive power, voltage, connectivity, temperature and wind speed are taken from wind farms every 12 seconds.
  - Based on this input, wind power production that may be fed into the power system is calculated, depending on the characteristics of the generators and the state of the system.
  - The calculation is performed with a breakdown by each individual wind farm and an aggregation for each transmission node. It is sent to the generation control centres which in turn communicate it to the producers as they have to modify the power consignment supplied to the grid.


Photo: Thinkstock

4 WAYS OF ENHANCING WIND POWER INTEGRATION

Flexible balancing solutions (generation capabilities, load management, energy storage) help facilitate the integration of wind power into power systems. Even though power system balancing is not new, wind power does provide new challenges at high penetration levels, because its variability characteristics require power systems to become more flexible. The type of flexibility required is the ability to adequately respond to fast and significant system load variations.

Put another way, in a system that is more flexible, the effort needed to reach a certain wind energy penetration level will be lower than in a less flexible system. In a system that spans a larger geographical area, a larger amount of flexible sources are generally available. The differences in power system sizes, dispatching principles and system flexibility explain why integration costs vary in different countries. For example a country like Denmark, where wind power meets more than 100% of power demand for several hours of the year, has a lot of flexibility because it is well interconnected, especially with the Nordic "hydro countries", which enables a high wind energy penetration level at low additional costs. Another example of a flexible power system that enables easy and low-cost wind power integration is Portugal, due to the high amount of fast responding reversible hydro power plants in the system.

Planning for integrating substantial amounts of wind power should consider what provisions (flexible sources) are needed to provide for additional flexibility in the system compared to a situation without wind power. In the assessment of the required additional flexibility, a distinction has to be made between the different market time-scales (hour/day ahead). The main sources for additional flexibility are: flexible generation, demand-side management (DSM), energy storage, interconnection and fast markets (markets with short gate closure). These are discussed briefly below:

- **Flexible generation:** Hydro-power is commonly regarded as a very fast way of reducing power imbalance due to its fast ramp-up and ramp-down rates. It is also an economically very efficient way of balancing because high wind energy production reduces power prices (see Chapter VI). This means that there is an economic case for shifting the hydro power production to a future time with less wind and higher power prices. Pumped hydro accumulation storage (PAC, see below) furthermore allows energy storage, making it possible to buy cheap electricity during low-load or high wind hours and sell it when demand and prices are higher. In the thermal generation category, gas fired units are the most flexible as they allow production to be rapidly adjusted. Furthermore, opportunities to make existing power plants more flexible – for example the ability to withstand more frequent starts and stops - should be further explored.

- **Demand-side management:** With demand-side management, loads are controlled to respond to power imbalances by reducing or increasing power demand. Part of the demand can be time shifted (for example heating or cooling) or simply switched off or on according to price signals. This enables a new balance between generation and consumption and reduces the demand peaks, without having to adjust generation levels.

  Demand-side management is less commonly applied today than flexible generation. The availability of this solution depends on load management possibilities (for example in industrial processes like steel treating) and the financial benefits flexible load contracts offer the load (cost of power-cuts and power-increases versus lower bills). Attractive demand side solutions in combination with decentralised storage are:
  - heat pumps combined with heat boilers (at home or district level)
  - cooling machines combined with cold storage
  - plug-in electrical vehicles – V2G concepts

  Each of these solutions permits the de-coupling of the time of consumption of electricity from the use of the appliance by means of the storage.

- **Energy storage options:** There is increasing interest in both large-scale storage implemented at transmission level, and in smaller scale dedicated storage *embedded* in distribution networks. The range of storage technologies is potentially wide. For large-scale storage, pumped hydro accumulation storage (PAC) is the most common and best known technology. PAC can also be done underground. Another technology option available for large-scale use is compressed air energy storage (CAES). Furthermore, an attractive solution consists of installing heat boilers at selected combined heat and power locations (CHP) in order to increase the operational flexibility of these units. Storage always involves loss of energy due to the conversion processes involved, and for example in the case of storage in the form of hydrogen production, the losses are substantial. If a country does not have favourable geographical conditions for hydro reservoirs, storage is not the first solution to look after because of the limited economic impact on system cost at moderate wind power penetration levels (up to 20%). This was for example found in the All Island Grid Study [DCENR, 2005]. Also in a study for the Netherlands [Ummels, 2009], it was found that besides some advantages in economic optimisation of the dispatch, large-scale storage can lead to higher CO_2 emissions in the system because it enables the dirtier plants - such as coal fired ones for example - to run for more hours and sell more power. Certainly, the use of storage to balance variations at wind plant level is currently far less economic than dealing with these variations at system level.

  The value of storage in providing spinning (standing, contingency) reserve was estimated for the UK by evaluating the difference in the performance of the system, fuel costs (and CO_2), when variability is managed via synchronised reserve only, compared to the performance of the system with storage facilities used to provide this reserve function [Strbac, 2007]. Considering the different levels of flexibility of generating capacity in the system, the capitalised value of the reduced fuel cost due to storage is as high as €1,164/kW for systems with low flexibility, and €302/kW for systems with high flexibility[4]. These are typical numbers that should be used in assessing the economic feasibility: in other words, can a storage plant be built for that cost?

- **Interconnection:** the interconnection capacity that is available for power exchange between countries is a significant source of flexibility in a power system. The capacity should be both technically and commercially available. Aspects related to the implementation and costs of improving interconnection are discussed in detail in Chapter 2.

- **Fast markets:** There is a lot of diversity in European power market rules. Day-ahead markets exist in nearly every country. The day-ahead forecast error for wind energy has gone down a lot in recent years thanks to improved weather forecast models, but the error is still higher than the intra-day forecast error. In the interest of minimising cost to consumers, the gate closure times should be reduced in order to bring down the uncertainty in forecasting and in this way reduce the last minute adjustments in balancing. Organising markets all over Europe to operate faster, on shorter gate closure times (typically three hours ahead) would dramatically improve the economics of integrating large amounts of wind power in the European power systems.

In several countries, studies have been carried out or are underway to investigate the consequences of the integration of large amounts of wind power in terms of additional reserve requirements, needs for flexible generation, operational practices in the power system, required reinforcements of the network and other integration solutions such as a more responsive demand and storage in the power system. Examples of such studies, in Germany, the UK, Ireland, the Netherlands, Denmark and other countries in the Nordic area are described on page 83 of this chapter.

[4] Conversion: 1 GBP = 1.2 EUR

5 WIND POWER'S CONTRIBUTION TO FIRM POWER

An important issue for power system design is how much installed wind power capacity statistically contributes to the guaranteed capacity at peak load. This firm capacity part of the installed wind capacity is called "capacity credit". Due to the variability of wind, its capacity credit is lower than that of other technologies. Nevertheless, there is a certain amount of firm wind capacity, which contributes to the adequacy of the power system.

This section briefly outlines system adequacy as defined by TSOs, and addresses the interaction of wind power and the system adequacy on these different levels.

5.1 Security of supply and system adequacy

The peak demand (or peak load) of electricity in Europe is still increasing. For the period up to 2020 ENTSO-E [ENTSO-E, 2010] expects an annual rise in the winter peak demand of 1.3 to 1.45% per year and slightly higher growth (1.5-1.7%) in the summer peak demand. The peak demand is a strategic parameter because it determines the generating and transmission capacities required. As a matter of convention, for system design purposes, peak load values at specific points of time in the year are being considered, notably in January and in July.

TABLE 2: AVERAGE ANNUAL PEAK LOAD GROWTH [ENTSO-E, 2010]

ENTSO-E Annual average peak load growth in %	2010 to 2015	2015 to 2020	2020-2025
January 7 PM	1.32	1.45	1.21
July 11 AM	1.49	1.66	1.32

The way the power system matches the evolution in the electricity demand is expressed by the term 'system adequacy'. The adequacy is made up of different components:

- The ability of the generation units in the power system to match the demand (load)
- The ability of the transmission system to carry the power flows between the generators and users

It is the system operators' task to maintain system adequacy at a defined high level. In other words, they should ensure that the generation system is able to cover the peak demand, avoiding loss-of-load events for a given level of security of supply. Various national regulations regarding this "security of supply" range from 99% security level (in one out of 100 years the peak load cannot be covered) to 91% (one event in 10 years).

5.2 Capacity credit is the measure for firm wind power

The contribution of variable-output wind power to system security – in other words the capacity credit of wind – should be quantified by determining the capacity of conventional plants displaced by wind power, whilst maintaining the same degree of system security, with the probability of loss of load in peak periods remaining unchanged.

The capacity credit of wind has been receiving special attention in many national wind integration studies [Giebel, 2005; Holttinen 2009], because in a way it is a 'synthetic' indicator of the potential benefit of wind as generator in the system. Sometimes the capacity credit of wind power is measured against the outage probabilities of conventional plants.

How is capacity credit determined?

There are basically two different ways of calculating the capacity value of wind power: by simulation and by probabilistic analysis.

In simulation methods, the secure operation of the system is observed and analysed by stepping through time-series data using simulation models. The results should be interpreted with care since single events tend to dominate the result [Giebel, 2003b].

The most significant events are special combinations of load and wind speed, especially in the high load period. In order to grasp the effect of such special combinations, a sensitivity analysis is performed, shifting the time series of wind power against the load data in steps of days. In the probabilistic method – which is the preferred method for system planning purposes - the availability of each power plant in the generation system is assessed. For instance, it is generally assumed that a coal power plant has an operational probability of about 96% and the probability of non-operational condition (scheduled or unscheduled) of 4%.

In order to take wind power into account, its capacity and probabilities have to be introduced into the model. The probability of the generation of individual wind turbines is determined by the wind regime, an assumption which automatically means there is a certain correlation between the power outputs of the individual wind turbines. A realistic representation needs to take smoothing effects into account, which arise from the geographical dispersion of wind farm locations. On the basis of the probabilities of individual power plants and the wind power, the probability of the whole generation system covering different load levels can be calculated.

Despite the variations in wind conditions and system characteristics among the European countries and regions, capacity credit studies give similar results. For low wind energy penetration, the relative capacity credit of wind power will be equal or close to the average wind power production (its capacity factor) in the period under consideration – which for generation adequacy planning purposes is the time of highest demand. For Northern European countries, the average wind power production in the winter time is typically 25 to 30% higher than the all year round average production. So, in these countries the capacity credit valid for adequacy estimations is positively influenced by a high seasonal capacity factor. As a general rule, the wind speed distribution in the high-load period is determining the spread of the substituted conventional capacity, for small as well as for high penetrations.

With increasing penetration levels of wind energy in the system, its relative capacity credit becomes lower. This means that every MW of new wind plant will substitute less conventional generation capacity than the MWs of wind plants formerly installed in the system.

Table 3 summarises the factors leading to higher or lower levels of capacity credit.

The TradeWind study investigated how the aggregation of power systems in Europe influences the European capacity value of wind power. Using a qualitative method, the study found that the capacity value of wind power at European level can be increased significantly by a higher degree of interconnection between countries. The effect of aggregating wind energy across multiple countries – studied with data for 2020 - increases the average capacity value of aggregated wind power by a factor of 1.7 compared to the wind power capacity value for single countries, as shown in Figure 6.

Thus, wind energy has significant capacity credit in a power system. The aggregated capacity credit of the wind farms in a system depends on many factors. It depends on the characteristics of the power system in question (reliability level, flexibility of the generation mix) and the penetration level of wind power in the system. It also depends on a range of wind and wind technology specific factors such as the average wind power capacity factor[5], where wind farms are in the system, and so on. The relative capacity credit decreases from a value approximately equal to the wind power capacity factor during high demand periods for low levels (25-35%) to approximately 10-15% at higher levels.

Despite the real technical and physical capacity value of wind power, it is not yet regularly used for capacity planning and is not given a value in power markets. One of the barriers is the absence of a standardised accepted method for calculating capacity value.

TABLE 3: FACTORS AFFECTING THE VALUE OF THE CAPACITY CREDIT OF A CERTAIN AMOUNT OF WIND POWER IN THE SYSTEM

Higher capacity credit (%)	Lower capacity credit (%)
Low penetration of wind power	High penetration of wind power
Higher average wind speed, high wind season when demand peaks.	Lower average wind speed
Lower degree of system security	High degree of system security
Higher wind power plant (aggregated) load factor (determined by wind climate and plant efficiency)	Lower aggregated capacity factor of wind power
Demand and wind are correlated	Demand and wind uncorrelated
Low correlation of wind speeds at the wind farm sites, (often related to large size area considered)	Higher correlation of wind speeds at wind farm sites, smaller areas considered
Good wind power exchange through interconnection	Poor wind power exchange between systems

[5] Capacity factor: depends on relation between rotor size and rating of generator.

As a consequence a large diversity can be seen in the estimation of the capacity value in the practice of system planning at European level by national TSOs, for example in the annual System Adequacy Forecast [SAF, 2010]. There is a need to establish and utilise a harmonised method for wind power capacity credit assessment in European generation adequacy forecast and planning, in order to properly evaluate the contribution of wind power to system adequacy. This would also constitute a basis for valuating wind power capacity in the future liberalised electricity market.

FIGURE 5: CAPACITY CREDIT OF WIND POWER, RESULTS FROM EIGHT STUDIES. THE IRELAND ESTIMATES WERE MADE FOR TWO POWER SYSTEM CONFIGURATIONS; WITH 5 GW AND 6.5 GW PEAK LOAD [HOLTTINEN, 2009]

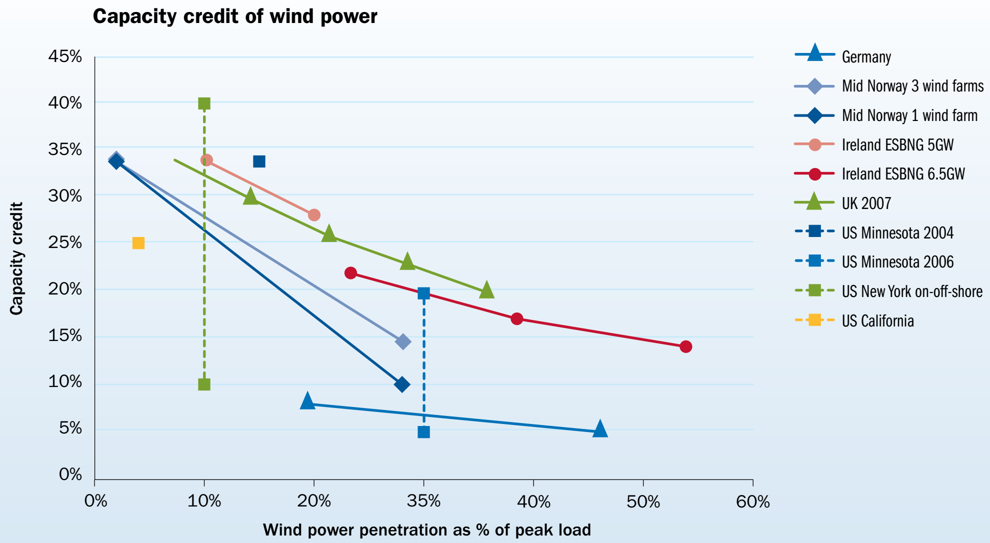
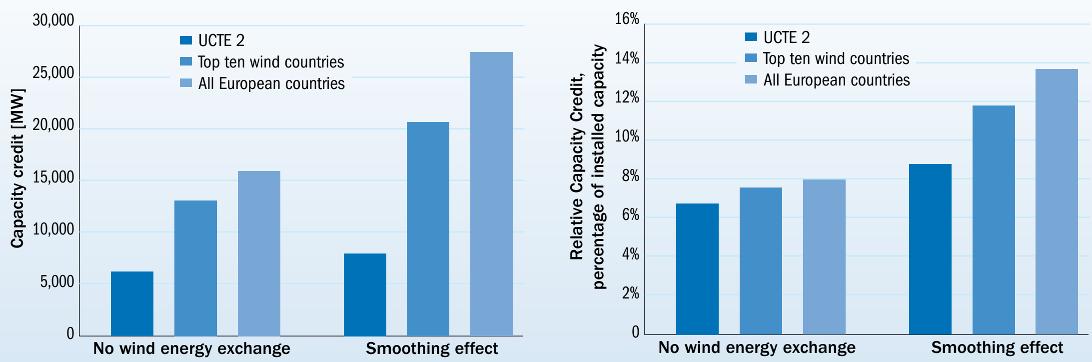


FIGURE 6: INCREASE IN CAPACITY CREDIT IN EUROPE DUE TO WIND ENERGY EXCHANGE BETWEEN THE COUNTRIES IN THE 2020 MEDIUM SCENARIO (200 MW, 12% PENETRATION) [TRADEWIND, 2009]. UCTE2 INCLUDES FRANCE, BENELUX, GERMANY, SWITZERLAND AND AUSTRIA



6 NATIONAL AND EUROPEAN INTEGRATION STUDIES AND EXPERIENCES

This section presents some findings from national system studies into wind power integration. Figure 7 shows the typical different levels of wind power penetration assumed system studies. The penetration level is indicated in three different ways (metrics):

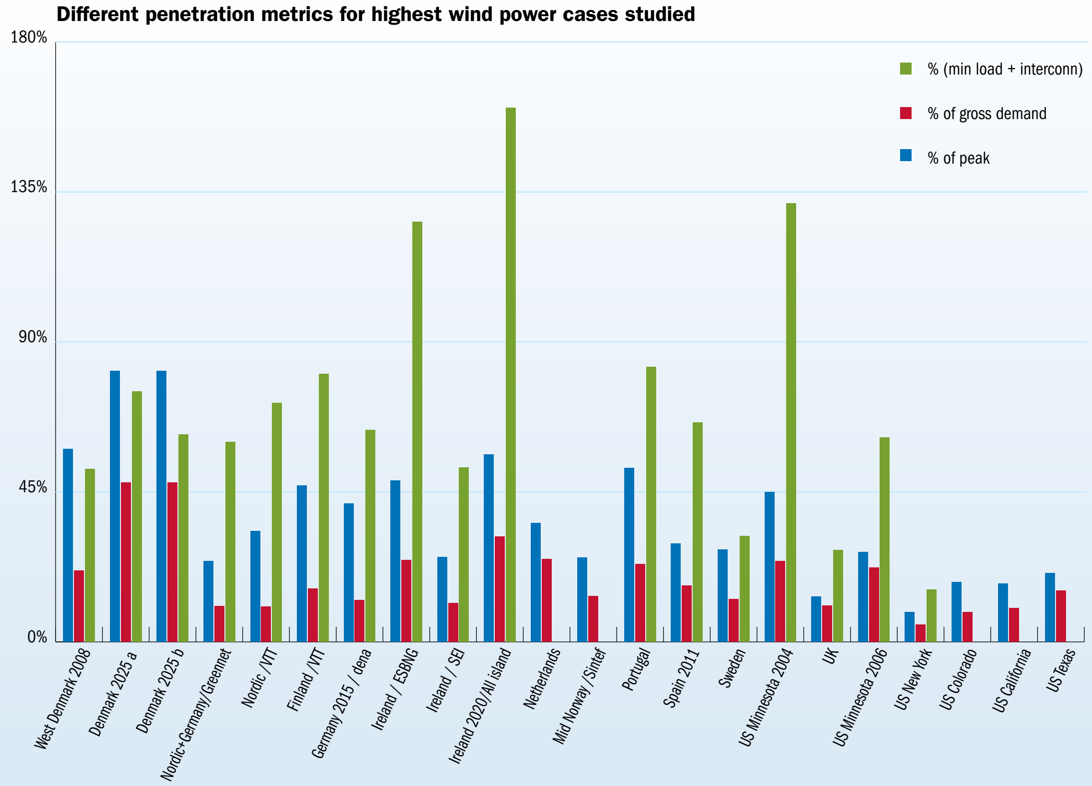
- As a percentage of gross annual electricity demand (energy penetration)
- As a percentage of peak demand (capacity penetration)
- As a percentage of minimum load plus available interconnection capacity

The first way (energy penetration) is most commonly measured in terms of percentage of energy (for example GWh). Studies range from 10% up to 50%. Denmark and Ireland are investigating high energy penetration levels.

The third definition gives an indication of how critical the penetration level is. In situations where the installed wind power capacity exceeds the minimum load minus the available interconnection capacity (over 100% in the figure below), there is a need for additional integration solutions, such as demand shift, adding interconnection capacity, looking for storage solutions and so on. Typically these critical situations are first reached in Ireland and UK (at comparable energy penetration levels with other countries), mainly as consequence of their "island" situation with relatively low degree of interconnection (fewer neighbours than other countries).

Further, it can be concluded from Figure 7 that results exist from studies looking at energy penetration levels up to 50%.

FIGURE 7: COMPARISON OF THE SHARE OF WIND POWER IN THE POWER SYSTEM (PENETRATION LEVELS) STUDIED



For studies covering several countries, the aggregated penetration level has been calculated. Individual countries within the study cases can have significantly higher wind power penetration levels [Holttinen, 2009].

6.1 Germany

The most prominent integration study in Germany is the DENA study published in 2005 and is still considered as a milestone. It looked into a scenario whereby there would be 15% wind energy penetration expected by 2015 (34 GW) [Dena, 2005]. It concluded that the required reserve capacities can be met with the existing generation plant configuration and its operating method as developed in this study. Wind power plant capacity and generation figures are given in Table 4. The study assumed a total generating capacity in Germany of 125 GW (2003), 40 GW of which have to be replaced before 2020 taking into account existing interconnectors at the German borders.

To balance the system with unforeseen variations in wind power, short-term and hourly reserves must be provided, capable of positive and negative regulation. In 2003, an average of 1.2 GW and a maximum of 2.0 GW of wind-related positive regulation power had to be available one day ahead in Germany. By 2015, that amount would rise to an average of 3.2 GW and a maximum of 7.0 GW. The mean value corresponds to 9% of the installed wind power capacity and the maximum to 19.4%. These capacities have to be available as positive minute and hourly reserves. In 2003, an average of 0.75 GW and a maximum of 1.9 GW of wind-related negative regulation power had to be available one day ahead. By 2015, that amount would rise to an average of 2.8 GW and a maximum of 5.5 GW. The mean value corresponds to about 8% of the installed wind power capacity, and the maximum to 15.3%.

TABLE 4: CHARACTERISTIC FIGURES FOR WIND POWER CAPACITY AND GENERATION IN 2003, 2009 AND 2015 BASED ON SCENARIOS IN THE DENA STUDY [DENA, 2005]

	2003	2009	2015
Installed wind power capacity (GW)	14.5	25.8	36
Annual wind energy generation (TWh)	23.5	46.8	77.2
Effective capacity factor	18 %	21 %	25 %
Wind energy share of annual electricity demand (gross)	5.5 %	7.6 %	14 %

The realised values for 2009 are given for comparison.

TABLE 5: OVERVIEW OF REQUIRED REGULATION POWER (DAY AHEAD RESERVE) IN 2003 AND 2015 AS FOUND IN THE DENA STUDY [DENA, 2005]

	2003		2015	
	Average	max	Average	max
Positive regulation capacity (MW)	1.2	2	3.2	7
% of wind power capacity	9	14	9	19
Negative regulation capacity (MW)	0.75	1.9	2.8	5.5
% of wind power capacity	5	14	8	15

Installed wind power capacity 14.5 GW in 2003, and 36 GW in 2015. These capacities (primary and secondary reserves) have to be scheduled to cope with unforeseen changes in wind power output with respect to the schedules.

In a follow-up study, the potential for increased integration of wind power through the creation of an intraday market was investigated [FGE/FGH/ISET, 2007]. It concluded that using an intra-day market has no particular advantage given the specific prices for reserve power, and the mean spot market price of €45/MWh.

6.2 Nordic region

An estimation of the operating reserve requirement due to wind power in the Nordic countries has been discussed in earlier studies [Holttinen, 2005 and Holttinen, 2004]. The results are presented in Table 6.

- The increase in reserve requirements corresponds to about 2% of installed wind power capacity at 10% penetration and 4% at 20% penetration. For a single country this could be twice as much as for the Nordic region, due to better smoothing of wind power variations at the regional level. If new natural gas capacity was built for this purpose, and the investment costs were allocated to wind power production, this would increase the cost of wind power by €0.7/MWh at 10% penetration and €1.3/MWh at 20 % penetration. For comparison, the retail price of electricity for households in Denmark is more than €250/MWh (2009).

- The increase in use of reserves would be about 0.33 TWh/year at 10% penetration and 1.15 TWh/year at 20% penetration. The cost of an increased use of reserves, at a price €5-15/MWh would be €0.1-0.2/MWh of wind energy at 10% penetration and €0.2-0.5/MWh at 20% penetration.

The additional balancing requirements in this case are significantly lower than, for example, the *Dena* report results. This is mainly due to two things: first, the area of study is much larger covering the whole of the four Nordic countries. This illustrates the advantages of operating the Nordic power system as a coordinated, integrated system. Secondly, the results are calculated from the variability during the operating hour, so forecast errors for wind power on longer timescales are not taken into account. The parties responsible for balancing in the Nordic power system have the opportunity to change their schedules up to the operating hour. This means that part of the prediction error can be corrected when more accurate forecasts arrive.

TABLE 6: THE INCREASE IN RESERVE REQUIREMENT DUE TO WIND POWER WITH DIFFERENT PENETRATION LEVELS, AS A PERCENTAGE OF GROSS DEMAND

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

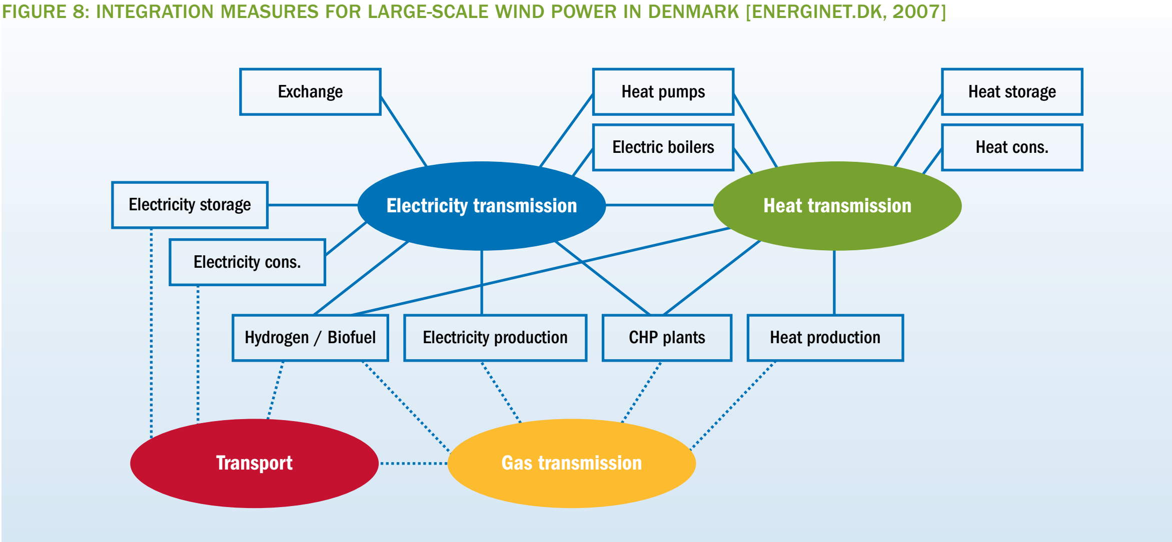
The increase in reserve requirement takes into account the better predictability of load variations.
The range in Nordic figures assumes that the installed wind power capacity is more or less concentrated.

6.3 Denmark

The Danish TSO Energinet has investigated the consequences of doubling the country's approximately 3,000 MW of installed wind power to about 6,000 MW before 2025 [Energinet, 2007; Eriksen & Orths, 2008]. About 2,000 MW is expected to be installed offshore. The change would increase wind power's share of Danish electricity demand from 20% to 50%. Assessments are made for the energy balance, the fuel consumption, the emissions, the power balance, the need for ancillary services and the transmission grid. More generally, the study assesses the demands that integration of 50% wind energy into the electricity system would place on flexibility in production, grid operation and power consumption.

The study shows that both *domestic* flexibility and *international* power markets are prerequisites for maintaining security of supply and maximising the economic value of wind power. Measures for integrating large-scale wind power involve a whole range of measures on the market side, on the production side, on the transmission side and on the demand

FIGURE 8: INTEGRATION MEASURES FOR LARGE-SCALE WIND POWER IN DENMARK [ENERGINET.DK, 2007]



side. Further connecting the electric power system to district heating systems, the transport sector (e.g. via electric vehicles) and energy storage systems are important components for such high levels of wind integration.

Countermeasures identified to prevent overloading of transmission lines through Jutland could be implemented on several sides of the power system:

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

The measures mentioned above were investigated by the Danish TSO and partners in research and development to enable the "+3,000 MW" 2025 scenario.

6.4 United Kingdom

With the rapid growth of wind power in the UK, the extent and cost of the provision of these additional operating reserves will need to be addressed. In the last few years, some studies have been carried out in the UK to comprehend the magnitude and cost of these additional system balancing requirements (Dale et al, 2003; MacDonald, 2003; UKERC, 2006).

Strbac et al. 2007 studied the impact of up to 20 GW of wind generation (most of it is offshore) on the operation and development of the UK electricity system taking into account the existing interconnector with continental Europe. The study assumed a rather high forecast error; in practice this reserve requirement could be less with good forecast systems (four hours ahead). The additional cost considered is only the cost for using additional reserves (not their capacity). On average, the UK system operator commits about 600 MW of dynamic frequency control, while about 2,400 MW of various types of reserve is required to manage the uncertainty over time horizons of around three-four hours. The reserve requirements are driven by the assumption that time horizons larger than four hours will be managed by starting up additional units, which should be within the dynamic capabilities of gas fired technologies.

The additional primary and secondary reserve requirements due to wind generation and their associated costs were calculated for various levels of wind generation in the system, in steps of 5 GW up to 20 GW. The increase in primary reserves was found to be relatively small for modest increases in wind power connected. However, at high wind penetrations, secondary levels equivalent to 25% of wind installed capacity are needed to cover the extreme variations in wind output.

The expected minimum figures correspond to a highly diversified wind output. With the large concentrations of wind power plants now expected in The Wash, Thames Estuary, North-west England and Scotland, the need for primary reserve is likely to be closer to the expected maximum. It was concluded that the amount of extra reserve can be handled with the current conventional power plants, so only the cost of increased operation of the existing reserves has been estimated in Table 7.

TABLE 7: ADDITIONAL REQUIREMENTS FOR CONTINUOUS FREQUENCY RESPONSE AND RESERVE FOR INCREASING WIND POWER PENETRATION IN UK

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

The expected minimum and maximum MW reflect the dispersion of wind power plants. Expected minimum and maximum of costs reflect also the reserve holding cost range £2–4/MWh. Cost converted from consumer costs in [Strbac et al., 2007] to €/MWh wind energy assuming £1 = €1.3 [Holttinen, 2009].

6.5 Ireland

Sustainable Energy Ireland published a report "Operating Reserve Requirements as Wind Power Penetration Increases in the Irish Electricity System" [Ilex et al., 2004]. The study findings were that fuel cost and CO_2 savings made with installed wind power of up to 1,500 MW wind power in the Republic of Ireland (ROI) system were directly proportional to the level of wind energy penetration. Over longer time horizons (one to four hours), there is an increasing requirement for additional operating reserve as wind penetration increases, as shown in Table 8. The study found that while wind did reduce overall system operation costs it could lead to a small increase in operating reserve costs €0.2/MWh for 9.5% wind penetration and €0.5/MWh for 14.3% of wind.

TABLE 8: ADDITIONAL RESERVE REQUIREMENT FOR DIFFERENT LEVELS OF INSTALLED WIND POWER [HOLTTINEN, 2009]

Wind power installed (MW)	% gross demand	One hour reserve requirement (MW)	Four hour reserve requirement (MW)
845	6.1	15	30
1,300	9.5	25	60
1,950	14.3	50	150

All Island Study

The All Island Grid Study [DCENR, 2005] was carried out on request of the governments of Northern Ireland and the Republic of Ireland to investigate the technical issues associated with the integration of high levels of renewable generation and the resulting costs and benefits. It concluded that a renewable (mostly wind) electricity share of 40% of the total demand could be integrated into the system, delivering around 25% reduction of CO_2 emissions for a maximum of 7% increase in total system costs. The key challenges to successfully integrate this renewable generation include the following:

- *Complementary portfolio of non-renewable generation* with the flexibility to complement the variable renewable generation without excessive cost or CO_2 emissions and ensuring that the market and regulatory structures can facilitate the delivery and continuation of the commercial viability of the required plant.
- *System control of the power system* so as to ensure continuing stability and reliability while facilitating the delivery of renewable generation.
- *Connection applications.* The Commission for Energy Regulation has mandated a grouped connection process known as "Gate 3" to provide certainty for generation developers and to optimise network development.

- *Network reinforcement* to enable the connection of large amounts of wind and other renewables and conventional generation, and the development of new interconnectors.
- *Flexible electric loads:* in addition to a flexible plant portfolio, electric loads also need to be more flexible. Besides domestic demand side management, electric vehicles (EVs) could complement wind generation by storing electricity and providing flexible demand.

In the meantime, the Irish government has set a target for electric vehicles of 10% of the total by 2020 with 2,000 on the road by 2012 and 6,000 by 2013.

6.6 Netherlands

The study [Ummels 2009] performed simulations for a range of wind power penetrations of 0-12 GW in the Netherlands, with 12 GW supplying approximately 33% of the Dutch annual consumption. Technical limits to the system integration of wind power in the Dutch system have been identified and the economic and environmental impacts of wind power on system operation quantified. Furthermore, the opportunities for energy storage and heat boilers for the integration of wind power in the Dutch system have been explored.

The high reserve levels provide sufficient ramping capacity for balancing wind power variability in addition to existing load variations, provided that accurate updates of wind power output and a continuous re-calculation of unit commitment and economic despatch are made. Although the additional variations introduced by wind power can be integrated, and do not present a technical problem, limits for wind power integration increasingly occur during *high wind and low load* periods. Depending on the international market design, significant amounts of wind power may have to be exported to prevent minimum load problems (Figure 9).

The integration of wind power benefits from postponed gate closure times on international markets, as international exchange may be optimised further when improved wind power predictions become available. The simulation results show that wind power production reduces total system operating cost, mainly by saving fuel costs. International exchange is shown to be of the utmost importance for wind power integration, especially at high penetration levels. As such, possibilities for international exchange – especially the reinforcement of the NorNed interconnector between Norway and the Netherlands - should be regarded as a promising alternative for the development of energy storage in the Netherlands itself. The results quantify the importance of the larger German system for the integration of wind power into the Dutch system.

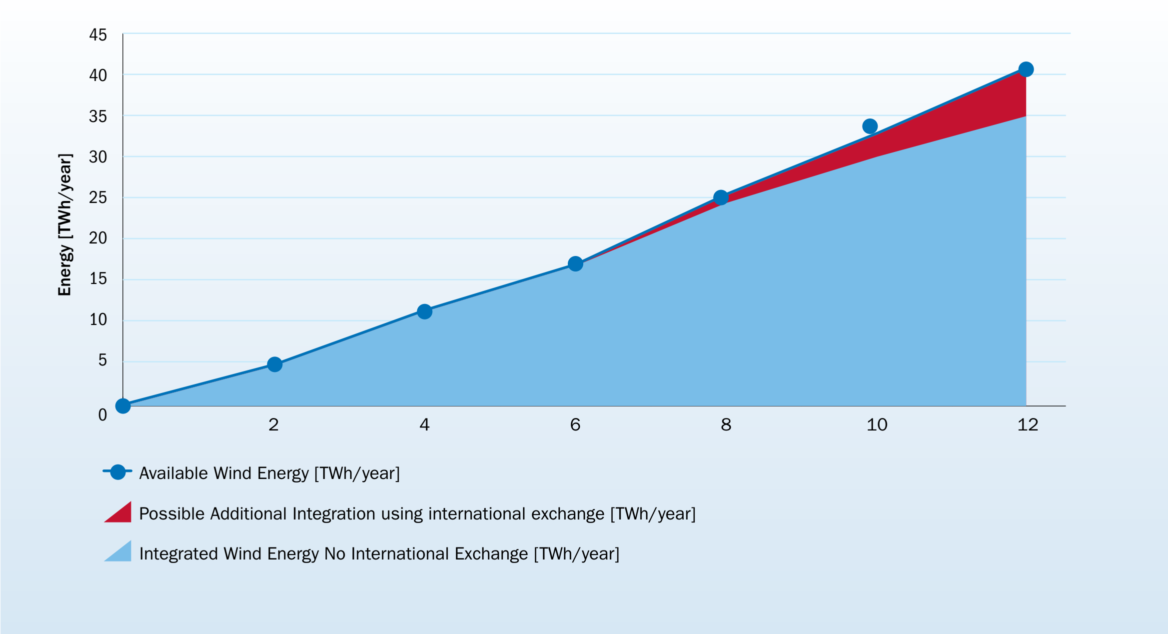
6.7 European Wind Integration Study

Under the umbrella of the former organisations ETSO and UCTE, 14 European System Operators started the European Wind Integration Study (EWIS) in 2007 to investigate the economic integration of wind energy into the transmission systems for the 2015 scenario with 10% wind energy penetration in Europe. Although an 'Optimistic' scenario with 185 GW installed wind capacity was considered, the best estimate scenario had 140 GW of installed wind energy capacity. Although it focused on integration solutions, the study also looked into other system operational issues, such as the required balancing reserves. Representing the wind diversity that can be exploited using the transmission network and the sharing of balancing measures that are possible between countries, EWIS models have shown how the operational costs associated with addressing wind variability are expected to be small compared to the overall benefits. The additional balancing costs would amount to some €2.1/MWh of wind produced in the best estimate scenario, and €2.6/MWh in the 'Optimistic' wind scenario, corresponding to no more than 5% of the calculated wind benefits in terms of reduced fuel and CO_2 emission costs.

Summary and key messages

- Ways of helping integrate large amounts of wind power into the power system include all possible

FIGURE 9: INTEGRATED AND WASTED WIND ENERGY IN THE NETHERLANDS [UMMELS, 2009]



measures to increase the use of flexibility sources (flexible generation, demand side response, power exchange through interconnection and energy storage) as well as an appropriate use of the active power control possibilities of wind plants. Wind plant power output control can help manage variability over short amounts of time when necessary for system security and when economically justified. Access to existing hydropower energy storage and other flexible balancing solutions should be maximised by improving interconnection, and for penetration levels up to those expected in 2020 there is no economic justification in building alternative large-scale storage.

- With increasing shares of wind power in the system, there will be additional balancing capacity needed, mainly to deal with the increased hour ahead uncertainty (load following reserves). With adequate use of short-term wind power forecasting, the need for this extra reserve capacity can be reduced. Existing conventional plants can often provide this capacity, but they have to be scheduled and operated in a different way. Besides using the existing plants – even the slow base load plants - in a more flexible way with increasing penetration, planning for replacing ageing plants and visions of the future generation mix should favour flexible generation (for example CCGT and hydropower) to enable the integration of large-scale variable generation. Providing better access to flexible reserves situated in neighbouring control areas through power exchange is also a way to improve the system's flexibility.

- Experience with high levels of wind power penetration (e.g. Spain, Denmark, Germany, Ireland) and a range of system studies provide insight into the additional reserves required for integrating the shares of wind power foreseen for 2020. The studies indicate 1-15% at 10% penetration, and 4-18% at 20% penetration. The large range in the numbers shows that many factors are in play; one of the most important aspects is the efficient use of forecasts. The additional balancing costs at penetration levels of 20% are in the range of €4/MWh of wind power, mainly due to increased operation of fuel reserves.

At European system level the EWIS study (penetration of 10%, time horizon up to 2015) found additional balancing costs in the order of €2/MWh, which is well in the range of the other studies. A very important common finding of system studies is that there is no steep change in required reserves or the cost of their deployment with increasing penetration. The estimations of the studies may be on the conservative side because in practice system operators use forecasts in a much better way than assumed in the models.

- Aggregating wind power over large interconnected areas and dispersed sites and using combined predictions helps to bring down the wind power forecast error to manageable levels in the time frames relevant for system operation (four-24 hours ahead). To help efficiently integrate wind power, forecasting tools should be installed in the control room of the system operator. The cost-benefit ratio of applying centralised forecast systems is very high – because of the high reduction in operational costs of power generation corresponding to reduction in uncertainty. Forecasting needs to be customised to optimise the use of the system reserves in the different time scales of system operation. It is important to develop ways of incorporating wind power uncertainties into existing planning tools and models, and in this area more R&D is needed.

- Clustering wind farms into virtual power plants enhances the controllability of the aggregated wind power for optimal power system operation. Practical examples, for instance in Spain, demonstrate the benefits of the coordinated operation of distributed variable generation sources as a means to manage their variability and enhance their predictability, supported by dedicated national and regional control centres put in place by the system operator.

- Wind power capacity replaces conventional generation capacity. The capacity credit of large-scale wind power at European level is in the order of 10% of rated capacity at the wind power penetration levels foreseen in the TradeWind medium scenario of 200 GW in 2020. Aggregating wind power from dispersed sites using and improving the interconnected network helps to increase its capacity credit.

Photo: REpower

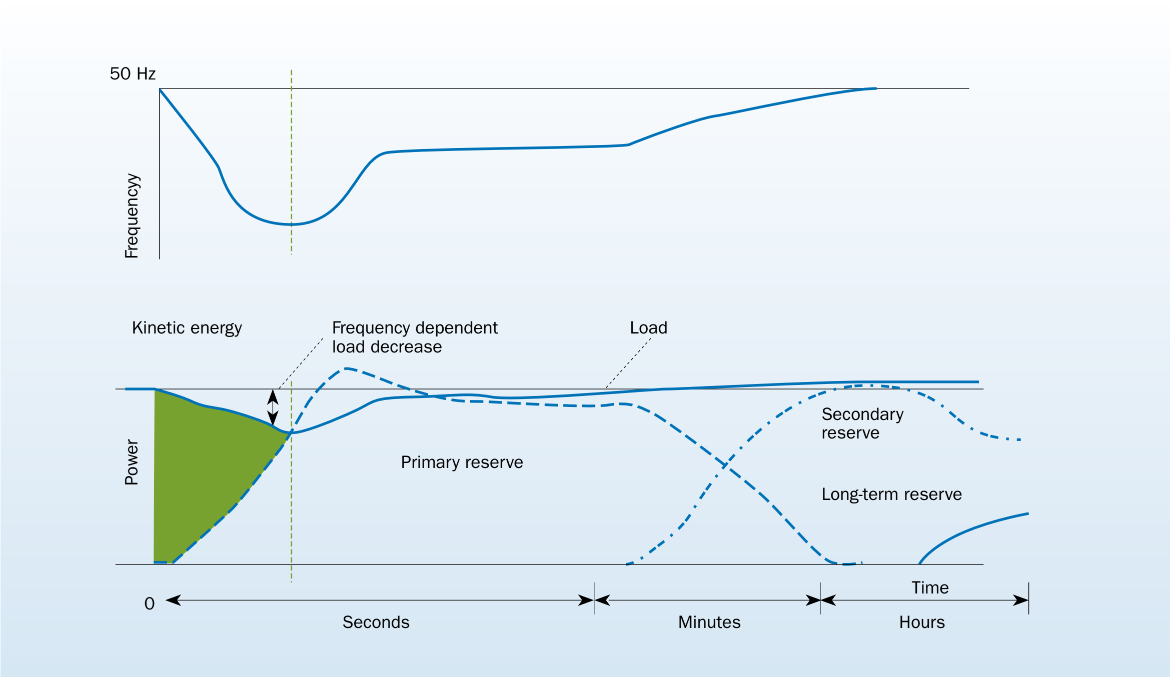
7 ANNEX: PRINCIPLES OF POWER BALANCING IN THE SYSTEM

In power systems, the balance between generation and consumption must be continuously maintained. The essential parameter in controlling the energy balance in the system is the system frequency. If generation exceeds consumption, the frequency rises; if consumption exceeds generation, the frequency falls. Ultimately, it is the responsibility of the system operator to ensure that the power balance is maintained at all times.

Power system operation covers several time scales, ranging from seconds to days. To start with, primary reserve is activated automatically by frequency fluctuations. Generators on primary control respond rapidly, typically within 30-60 seconds. Such imbalances may occur due to the tripping of a thermal unit or the sudden disconnection of a significant load. An immediate response from primary control is required to re-instate the power balance, so that the system frequency is at a stable value again. For this near-immediate response to power imbalances, sufficient generation reserves must be available by generation units in operation. Secondary reserve is active or reactive power activated manually or automatically in 10 to 15 minutes after the occurrence of frequency deviation from nominal frequency. It backs up the primary reserve and it will be in operation until long-term reserves substitute it. The secondary reserve consists of spinning reserve (hydro or thermal plants in part load operation) and standing reserve (rapidly starting gas turbine power plants and load shedding).

Because changes in loads and generation, resulting in a power imbalance, are not typically predicted or scheduled in advance, primary and secondary controls operate continuously to keep system frequency close to its nominal value.

FIGURE 10: PRINCIPLE OF BALANCING IN THE POWER SYSTEM



Consumption of electrical power varies per minute, hour and day. Because the power balance must be continuously maintained, generation is scheduled to match these longer term variations. Such economic dispatch decisions are made in response to anticipated trends in demand (while primary and secondary controls continue to respond to unexpected imbalances). During the early morning period, for example, an increase in load usually occurs from approximately 7 AM to midday or early afternoon. After the daily peak is reached, the load typically falls over the next several hours, finally reaching a daily minimum late at night.

Some generators require several hours to be started and synchronised to the grid. That means that the generation available during the midday peak must have been started hours in advance, in anticipation of the peak. In many cases, the shut-down process is also lengthy, and units may require several hours of cooling prior to restarting. The decision to utilise this type of unit often involves a period of several days that the unit must run prior to shutting down in order to be economic. This time-scale is called unit commitment, and it can range from several hours to several days, depending on specific generator characteristics and operational practice.

During operations, the balancing task is usually taken over from the individual power producers by the system operator. This is cost effective, as the deviations of individual producers and loads smooth out when aggregated, and only the net imbalances in the system area need to be balanced to control the frequency. System operators have the information on schedules for production, consumption and interconnector usage. These schedules either are made by themselves or are provided by electricity market or actors involved (producers, balance responsible players or programme responsible parties). They may also use on-line data and forecasts of for example load and wind power to assist in their operational duty. During operations, they follow the power system and call producers that have generators or loads as reserves to activate them as and when they need, to balance the power system.

4 UPGRADING ELECTRICITY NETWORKS – CHALLENGES AND SOLUTIONS

1 DRIVERS AND BARRIERS FOR NETWORK UPGRADES

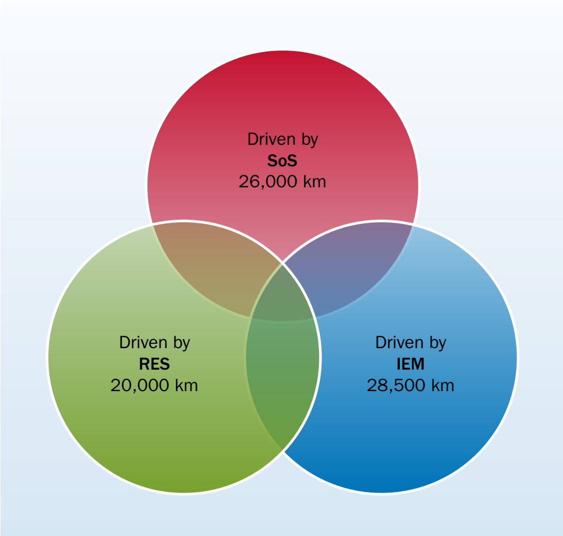
Upgrading the European electric power network infrastructure at transmission and distribution level is perhaps the most fundamental step on the way to reaching the EU's mandatory target to meet 20% of our energy from renewable energy sources, including increasing the share of renewable electricity from 15% to 34% by 2020. Equally, renewable energy – together with security of supply, energy independence and developing the internal market - has become a significant driver for expanding, modernising and interconnecting the European electricity networks. Better interconnected networks bring significant benefits for dispersed renewable power by aggregating (bringing together) dispersed (uncorrelated) generation leading to continental smoothing, improved predictability and a higher contribution from wind power capacity to peak demand.

The transmission systems in Europe were designed and built for a very different power mix to the one we have today and will have tomorrow [Orths&Eriksen, 2009]. In fact, in its early days 100 years ago, electricity was supplied from distributed generation and it is only for the last 50 years or less that transmission systems have been planned for a supply concept based on ever larger central units. Historically, there was little European cross-border transmission capacity between UCTE countries or between the UCTE and other synchronous zones (Nordel, UK, Ireland).

At that stage, using substantial amounts of renewable energy, with the exception of large hydro, was not considered; neither were the concepts of virtual power plants or of trading electricity on a spot market. The changing flows in the system demonstrate the need to expand and reinforce the grids to optimise the transportation of power from generators to consumers. More flexibility, new technology and grid management concepts also need to be introduced to prepare the power systems for future distributed and variable generation. In the debate about future networks, two concepts are omnipresent: the Supergrid and Smart Grids. Although these terms do not have a fixed definition, their widespread use testifies to a consensus that network upgrades are generally expected to be take the form of a highway-type interconnection (Supergrid) with more communication and intelligence (Smart grids), properties that are certainly advantageous to large-scale integration of wind power. Another major driver for grid upgrades is the emerging internal electricity market (IEM) in Europe, requiring sufficient transport capacities between regions and nations to enable effective competition in the power market to the benefit of European consumers.

In its first edition of the Ten Year Network Development Plan [ENTSO-E, 2010], the transmission system operators, ENTSO-E, estimated the required expansion of the network – focusing on lines of European interest – for the years up to 2020, quantifying the drivers in terms of system security (SoS), renewables (RES) and electricity markets (IEM).

FIGURE 1: MAIN DRIVERS FOR INVESTMENT IN NEW OR REFURBISHED POWER LINES (PROJECTS OF EUROPEAN SIGNIFICANCE) [ENTSO-E, 2010]



In addition to the upgraded and new network infrastructure, a proper legal framework is needed, so the capacity can be fully exploited. At European level, two major initiatives contain basic elements of such a framework:

- The European Renewable Energy Directive (2009) stipulates that national governments and TSOs should guarantee renewables sufficient transmission capacity and fair access to the transmission network.
- The mandatory ownership unbundling of generation and transmission as required by the proposed third Liberalisation Package (2008) should provide the legal basis to guarantee a level playing field with other generators.

In practice, carrying out the required network upgrades, especially building new lines, is a very lengthy process. Therefore, and because of the difference in speed between wind power development and transmission development, fair access rules are needed for the majority of instances where power lines are shared between wind energy and other power generators. Uniform rules do not yet exist at European level, and grid access for wind energy is currently conducted in a rather ad-hoc way. Some countries such as Germany and Spain take the recommendation from the 2009 RES Directive into account, and grant priority access to wind power to a certain extent. In practice, in cases where available grid capacity is limited, the principle of 'connect and manage' is often followed. At distribution level it is often 'fit and forget'. The wide range of different times taken to obtain a grid connection permit for a wind farm in the different EU countries (as identified in the 2010 WindBarriers project) reflects the lack of consistency between national policies in Europe in dealing with the issue of joint planning for new (renewable) generation and for network expansion.

Adapting the transmission infrastructure to uncertain future needs is a complex process that is subject to strategic planning, and includes the following steps:

- Short term: optimisation of the utilisation of the transmission network
- Mid- and long term: creation of Europe-wide onshore and offshore grids

There are some barriers related to network upgrades and extensions, specifically the construction of new lines:

- Long lead times in view of the planning procedures. Nowadays in many regions in Europe it can take seven or more years to get from the initial idea for a new overhead line to its actual implementation, mainly because of lengthy planning and permitting procedures influenced by social acceptance problems
- Need for substantial amounts of capital for network upgrades
- Absence of proper cost allocation mechanisms for multi-country and multi-user transmission lines
- Planning of grid investments and planning of wind farms are largely independent processes

Transmission planning in Europe is at a critical stage. Crucial political decisions have been taken at European level in the past five years, including the RES Directive (2009/28) and the next big step in energy liberalisation, the Third Package. The most relevant development in terms of network infrastructure is the creation of a pan-European association for network operators, ENTSO-E, as well as the revision of Directives spelling out the role of network operators and regulators in a more liberalised market. In this respect, the TYNDP of the ENTSO-E should be the main tool for providing a pan-European planning vision for grid infrastructure in line with long-term EU policy targets for renewables, including the National Renewable Energy Action Plans (NREAPs).

Photo: Thinkstock

2 IMMEDIATE OPPORTUNITIES FOR UPGRADE: OPTIMAL USE OF THE NETWORK

In the short term, and at relatively low levels of wind power penetration, transmission upgrades often coincide with methods of congestion management and optimisation in the transmission system. Moreover, there exist technical measures which do not involve excessive expenditure, but instead avoid or postpone network investments. A number of attractive technologies exist that have significant potentials for accelerating grid capacity and easing wind energy integration are discussed here.

Dynamic line rating with temperature monitoring

Dynamic line rating allows existing power lines to be used in a more optimal way by operating them at higher capacities by monitoring the temperature. Transmission capacity increases with the cooling effect of certain weather conditions, such as the wind blowing. The amount of power produced by wind power plants is obviously higher when it is windy. Hence, the use of dynamic line rating with temperature monitoring would ease the transmission constraints associated with a large wind power output. The amount of wind power produced also tends to be higher at night and during cooler periods of the year, so again dynamic line rating would allow more transmission capacity to be used. This approach is already in use in a few places, and industrial solutions are available[1]. The standardisation of this method is ongoing. A study for Germany [Burges, 2006] has quantified the possibilities for dynamic line rating, and found significant opportunities depending on the regional climate and wind conditions.

[1] It is relevant to consider this solution also for the more general case with more renewables in the grid. Then it is found that solar power output tends to be higher during hotter times of day, when transmission capability is lower. Still, it is likely that dynamic line ratings would benefit solar too, since most of the time transmission lines limits are likely too conservative.

Rewiring with high temperature conductors

Rewiring existing lines with low sag, high-temperature wires offers the possibility to increase the overhead line capacity by up to 50%, as electrical current carrying capacity directly depends on the power line sag and the line temperature. Depending on the specific situation, rewiring may be possible without having to obtain a permit, thus offering a fast way to significant transmission capacity enhancement.

Power flow control devices

The installation of power flow control devices in selected places in the network can help to optimise the utilisation of the existing grid. Flexible AC Transmission Systems (FACTS[2]) are widely used to enhance stability in power systems, but some FACTS solutions also support power flow control. Physically, in large radial European transmission networks, there is a lack of power flow controllability, because there is only one way for the power to flow. The lack of controllability can sometimes lead to congestion on a specific transmission line while there is still capacity on alternative lines. Since large-scale wind power changes the pattern of generation in the grid, the growth of wind power can increase the economic feasibility of AC power flow control. An example of this was shown in TradeWind simulations [TradeWind 2009], where increased wind power generation in central Norway would cause the corridor to Sweden to overload while there was still free capacity on the corridor to south Norway. One option in this case would be to reduce the hydro generation in central Norway when the wind speeds are high, but according to research, this would not be the preferred market solution if there were a possibility to control the AC flow. Consequently, it may be economically attractive to control the flow in certain AC lines, even if it would cost in terms of investment in auxiliary equipment. Thus, power flow control can ensure that existing transmission lines are utilised to the maximum, which is important given the public's reluctance to accept additional power lines, and the long-term project implementation which is normally associated with reinforcement of transmission systems.

Technologies that can help implement new network operation strategies

An assessment of the online dynamic network security by Wide Area Monitoring (WAMS) may substantially reduce traditional conservative assumptions about operational conditions, and thus increase the actual transfer capability of a power system. WAMS uses advanced GPS based surveillance tools to enable network operators to react in close-to-real-time for trading, fault prevention and asset management, and thus maintain the required reliability and system performance with increasing renewable generation. There are some organisational and regulatory challenges for the wide-spread introduction of WAMS, notable the need for standardised monitoring technologies, synchronised data acquisition and online data exchange.

Using distributed wind plants to improve transmission operation

Investments in the grid also can be reduced by the technical capabilities of the wind farms themselves, in particular when combined with technologies that improve the control of reactive power. This could for example be achieved by installing wind power plants at selected sites along the transmission grid especially for the purpose of grid support, which has a similar effect to installing FACTS. The advantage of wind plants over FACTS is that they produce energy in addition to grid support.

[2] FACTS (Flexible AC Transmission Systems): power electronic devices locally implemented in the network, such as STATCOMs, SVC's etc.

Photo: Jan Oelker

3 LONGER TERM IMPROVEMENTS TO EUROPEAN TRANSMISSION PLANNING

Transmission planning is based on a careful assessment of the expected development of generation – including wind power – and demand, as well as an analysis of the current network infrastructure (congestions/ replacement needs) to maintain security of supply. Input for these analyses is delivered by a range of studies as explained in the next section.

The development of offshore grids is of course part of this process. However because of the specific issues involved, offshore grids are dealt with in a separate section (see page 106)

3.1 Recommendations from European studies

Several studies at national and European level are now underway to back up the plans for upgrading the European transmission system in order to facilitate large-scale wind power integration. The most important recent international studies are TradeWind (www.trade-wind.eu) and EWIS (www.wind-integration.eu). Studies like these, which analyse the grid extensively – including both steady-state load flow and dynamic system stability analysis – are essential for quantifying the reinforcement needed to maintain adequate transmission with increasing wind power penetration.

TradeWind findings on grid upgrades

The TradeWind study (2006-2009) was undertaken by a wind energy sector consortium coordinated by EWEA. The project investigated grid upgrade scenarios at European level that would be needed to enable wind energy penetration of up to 25%, using wind power capacity scenarios up to 2030.

TABLE 1: ASSUMED WIND POWER CAPACITIES IN THE TRADEWIND STUDY (GW) [TRADEWIND, 2009]

Scenario	2005	2008	2010	2015	2020	2030
Low	42.0	56.2	69.0	101.3	140.8	198.9
Medium	42.0	64.9	85.4	139.3	199.9	293.5
High	42.0	76.0	105.0	179.1	255.8	364.9

TradeWind used a network model to look at how congestion develops in the interconnectors as more wind is connected to the system. The model applied reinforcements to the transmission lines that showed the largest congestions, in three different stages, and calculated how far these reinforcements could reduce the operational cost of power generation.

The TradeWind simulations show that increasing wind power capacity in Europe leads to increased cross-border energy exchange and more severe cross-border transmission bottlenecks in the future. With the amounts of wind power capacity expected in 2020 and 2030, congestion on several national borders (France, the UK, Ireland, Sweden, Germany, Greece) will be severe, if left unsolved. The major transmission bottlenecks were identified, with special attention paid to the interconnectors of 'European interest' according to the Trans-European Networks programme of the European Commission[3] (see Section 3.1.3). The effect of stormy weather conditions on cross-border flow was also investigated.

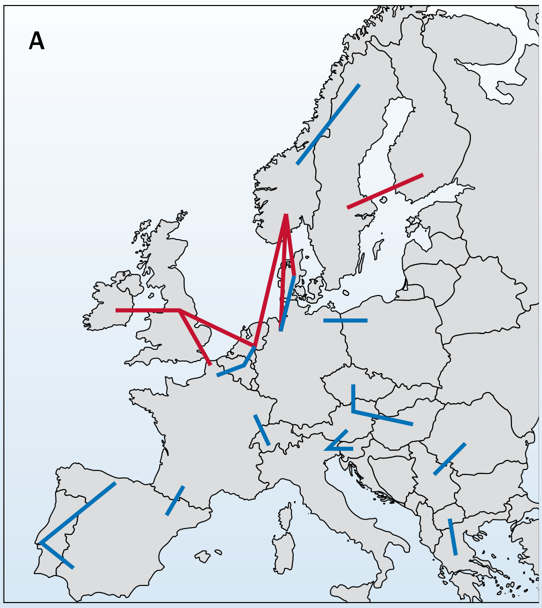
Wind power forecast errors result in deviations between the actual and expected cross-border power flows on most interconnectors over a substantial part of the time and will further exacerbate any congestion.

Based on the costs of these congestions, network upgrades that would relieve existing and future structural congestion in the interconnections were shown to have significant economic benefits.

More specifically, TradeWind identified 42 interconnectors and a corresponding time schedule for upgrading that would benefit the European power system and its ability to integrate wind power. In a perfect market, the upgrades would bring savings in operational costs of power generation of €1,500 million/year, justifying network investments in the order of €22 billion for wind power scenarios up to 2030.

An important finding of TradeWind was that the grid reinforcements would bring substantial economic benefits to the end consumer, no matter how much wind power was included. A preliminary economic analysis of a meshed offshore grid linking 120 GW offshore wind farms in the North Sea and the Baltic Sea and the onshore transmission grid showed that

FIGURE 2: PROPOSED INTERCONNECTOR UPGRADES FROM TRADEWIND (A AND B) AND EWIS (C)



[3] http://europa.eu/legislation_summaries/energy/internal_energy_market/l27066_en.htm

it compares favourably to a radial connection for individual wind farms, mainly due to the greater flexibility that it offers, as well as the benefits for international trading of electricity.

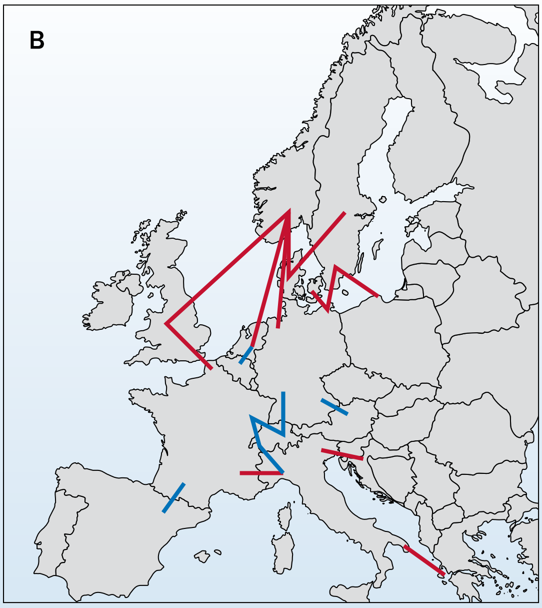
TradeWind was the first scientific project to study the Europe-wide impact of high amounts of wind power on the transmission grids. Parts of the methodology and the models have been taken up in further projects such as RealiseGrid[4], OffshoreGrid[5], RE-Shaping[6].

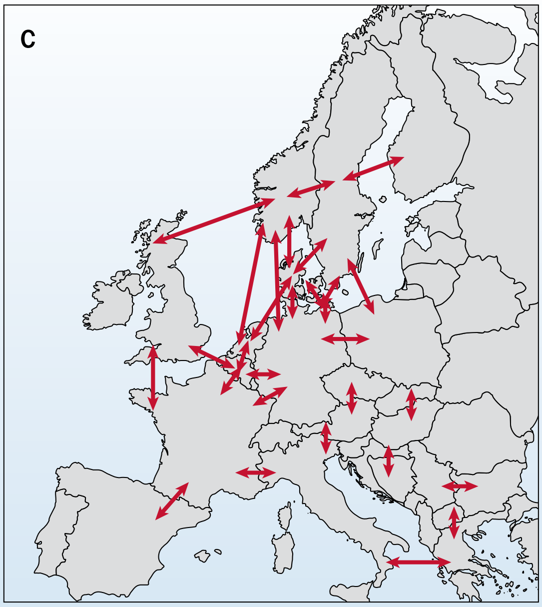
EWIS findings on necessary grid upgrades

EWIS (European Wind Integration Study) (2007-2010) was carried out by 15 European TSOs. The project[7] investigated the changes to the grid that would be needed to enable the wind power capacity foreseen for 2015, using the same assumptions as TradeWind on installed wind power capacities for 2015. The EWIS "Best-Estimate" scenario corresponds to the TradeWind "2015 Medium" scenario, and the EWIS "Optimistic" scenario corresponds to the TradeWind "2015 High" scenario (see Table 1). EWIS also created an "Enhanced Network" scenario, which was business as usual plus some reinforcements of some pinch points in the network.

The EWIS study [EWIS, 2010] identified 29 potential cross-border reinforcements (almost half of them for offshore) with an indicative capital cost of €12.3 billion. The cost of network developments currently planned - primarily in order to accommodate the additional wind power between 2008 and 2015 - were estimated between €25 and €121 per installed kW of wind power capacity. €121 kW of wind power capacity represents around €4/MWh (wind energy) which is similar to the additional operational costs for addressing the added variability by wind power (see page 106) and is small compared to consumer prices and the overall benefits of wind generation.

EWIS used a market model in a year-round analysis to identify two particular critical points in time: a High Wind North and a High Wind South situation.





4 http://realisegrid.erse-web.it/
[5] http://www.offshoregrid.eu/
[6] http://www.reshaping-res-policy.eu/
[7] http://www.wind-integration.eu/

In High Wind North, loop flows occur in and around Germany above all. As a consequence, specific capacity enhancement measures like dynamic line rating have been identified, as have phase shifting transformers. In its dynamic models for analysing the impact on the network, EWIS assumed that the wind power plants have capabilities (such as active and reactive power, fault ride-through) that match the grid connection features required today in areas with high wind penetration.

Economic analysis of EWIS showed that the costs of the various transmission upgrade measures proposed are outweighed by the benefits brought about by the reinforced European network. EWIS' recommendations are being used by ENTSO-E as a constituting element of the future network planning – for example in their first Ten Year Network Development Plan (TYNDP; see below for more information).

The EWIS study concluded that the wind power capacity assumed for 2015 can be integrated into the European power systems by addressing specific "pinch points" in the network with the appropriate reinforcement measures.

Since 2009, the planning of transmission upgrades at European level has been entrusted to ENTSO-E. This planning process must be transparent and carried out in close consultation with the various stakeholders – which include the wind energy sector and EWEA. The planning process is supervised by the European regulators (ACER) to ensure consistency with national network development plans. One of the vehicles of the consultation process is a document that ENTSO-E has to provide on a regular basis (every two years as of March 2012), containing a comprehensive vision of the expected and necessary Europe-wide transmission development, namely the Ten Year Network Development Plan 2010 (TYNDP). ENTSO-E issued a first "pilot" release of this TYNDP in June 2010 [ENTSO-E, 2010].

The TYNDP also points out what new transmission infrastructure can be used with sustainably mature new technologies, as well as providing long-term visions from both TSOs and stakeholders up to 2050 (including Smart grids and the Supergrid). The modelling of integrated networks in the TYNDP builds on inputs and results of the EWIS study [EWIS, 2010] in order to assess the most probable power flow patterns. The plan contains an identification of investment gaps and investment projects, particularly with respect to the development of cross-border capacities. With respect to the integration of offshore wind power, the Plan links to the work of the EU coordinator for "Connection of offshore wind power in Northern Europe".

The document is of strategic importance because of its links with the European policy framework. It should be a basis for further input and discussions by regulators towards clarification of the cost allocation aspects for new infrastructure and cost recovery via tariffs for projects of European interest, regional projects and national projects.

The aim behind the 2010 Pilot version of the TYNDP was to be the first plan for Europe that was put together in a structured way and not just by assembling projects planned by each TSO. However this has not been fully achieved in the pilot version which does not yet (mid 2010) include the 2020 energy policy goals, or the Member States' mandatory renewable energy targets.

European Commission framework for improved interconnection

By promoting a proactive approach to interconnecting Member States, the European Union's Trans-European Networks for Energy (TEN-E) programme intends to offer a vehicle for fostering wind power integration. TEN-E aims to help with the following:

- Effective operation of the internal market in general, and of the internal energy market in particular
- Strengthening economic and social cohesion by reaching the more isolated regions of the Community
- Reinforcing security of energy supply

Since 2006 the TEN-E programme has undergone changes. One of the programme's basic weaknesses is that it only provides support for feasibility studies.

It was found that despite TEN-E, the progress made in realising interconnection projects has been very slow. An attempt to accelerate the programme was made first by defining which projects were of European interest, appointing coordinators to these projects and providing limited structural funding to some of the projects. As part of the Commission's new energy policy, it was decided to appoint coordinators to three projects considered critical for Europe. One of the coordinators was specifically appointed for transmission projects that support the development of offshore wind power development in Northern Europe. However, this did not solve TEN-E's fundamental shortcoming: that it remains only loosely aligned with EU energy policy goals such as ensuring security of supply, creating a truly internal energy market and the increase in the share of renewable electricity from 15% in 2005 to 34% in 2020. All in all, TEN-E funding has until now proven to be insufficient as an incentive mechanism for investments in cross-border infrastructure.

As a consequence, the European Commission is preparing a proposal for a new EU Energy Security and Infrastructure Instrument, as requested by the European Council in March 2009 and anticipated in the Communication on the Second Strategic Energy Review (2008) and on the Green Paper on energy networks (2008) for the beginning of 2011. The European Commission has identified several areas of improvement for a revised TEN-E instrument in its recent progress report on the implementation of the programme[8].

- Simpler project categories: single cross-border transmission projects and several projects clustered into one regional scheme where appropriate
- Closer coordination between structural funds and the European Investment Bank (EIB). Financing tools for new energy infrastructure investments should be sought.
- Coordination and cooperation between Member States should be strengthened. Planning procedures should be streamlined to ensure a fast, transparent and reliable permitting scheme that includes binding deadlines for authorities. As well as prioritising projects at European level, the necessary support must be ensured at national level. TEN-E could also build on the positive experience of European "coordinators", particularly where the coordinator has a clearly defined objective – as does the French-Spanish interconnector.
- Finally, the deliverables of the third Liberalisation package and TEN-E projects must be coordinated. Transmission system operators (TSOs) and European energy regulators must support all TEN-E projects by including them in the forthcoming ten year network development plans by ENTSO-E with a clear timetable for implementation.

[8] http://ec.europa.eu/energy/infrastructure/studies/doc/2010_0203_en.pdf

Photo: Gehring

4 OFFSHORE GRIDS

4.1 Drivers and stepping stones

The case for an offshore grid

The exploitation of Europe's offshore wind potential brings new challenges and opportunities for power transmission in Europe. EWEA expects Europe's offshore capacity to reach 150 GW in 2030.[9]

The majority of the sites currently being considered for offshore wind projects are situated close to the European coast, not further than 100 km from shore. This is in part due to the high cost of grid connection, limited grid availability and the absence of a proper regulatory framework for wind farms that could feed several countries at once. Looking at the North Sea alone, with its potential for several hundreds of GW of wind power, an offshore grid connecting different Member States would enable this wind power to be evacuated to the load centres and at the same time facilitate competition and electricity trade between countries. A multi-terminal offshore grid would be able to link to offshore wind plants far from shore – as currently planned for Germany and the UK, for example. The draft working plan for the Pentalateral Energy Forum[10] summarises the advantages of such a grid:

1. Security of supply

- Improve the connection between big load centres around the North Sea

[9] EWEA's report 'Pure Power: Wind energy scenarios for 2020 and 2030' on www.ewea.org
[10] Draft Working Plan Proposal for Offshore Electricity Infrastructure, Belgian Ministry of Energy, Unpublished, 2010

- Reduce dependency on gas and oil from unstable regions
- Transmit indigenous offshore renewable electricity to where it can be used onshore
- Bypass onshore electricity transmission bottlenecks

2. Competition and market

- Development of more interconnection between countries and power systems enhances trade and improves competition on the European energy market
- Increased possibilities for arbitrage and limitation of price spikes

3. Integration of renewable energy

- Facilitation of large scale offshore wind power plants and other marine technologies
- Enabling wind power and other renewable power's spatial smoothing effects, thus reducing variability and the resulting flexibility needs
- Connection to large hydropower capacity in Scandinavia, introducing flexibility in the power system for compensation of variability from wind power and other renewable power
- Contribution to Europe's 2020 targets for renewables and CO_2 emission reductions

With the technology currently available, most offshore wind power is being developed and expected in the shallower waters of Northern Europe where the wind energy resource is attractive. As a result, offshore grid activities and plans focus mainly on the North Sea, the Baltic Sea and the Irish Sea.

Growing a transnational offshore grid from national initiatives

Most of the electricity grids in the world were built bottom-up, connecting local producers to nearby offtake points, and this will not be different with the offshore grid. An offshore grid would take decades to be fully built. Even implementing a single line can be very lengthy (depending mainly on the permitting procedures). A transnational offshore grid that interconnects wind farms and power systems in a modular way could be built in three main stages:

Stage I: Interconnected local (national) grids

Countries connect offshore wind power to the national grid. Point-to-point interconnectors are built in order to trade between national power systems. Onshore connection points for wind power are identified. Dedicated (HVDC) offshore lines are planned and built by TSOs to connect clustered wind power capacity. Dedicated regulatory regimes are established for offshore transmission, enabling TSOs to recover investments via the national electricity market. In the meantime, regulatory regimes are gradually becoming more internationally focused. The necessary onshore transmission reinforcements are identified. Preparations are made for multilateral grid planning. In parallel, HVDC VSC technology is developed and standardised at accelerated speed.

Stage II: Transition to transnational interconnected grid

Grids are planned multilaterally. Long-distance lines dedicated to offshore wind farms are planned and implemented. Pilot projects for connecting offshore wind power to different markets are implemented (Kriegers Flak, super-node, COBRA). HVDC VSC technologies are tested and optimised based on operational experience. The locations of planned offshore interconnectors are adapted to connect offshore wind farms. The locations of planned wind farms are adapted so they can connect to the grid via existing interconnectors.

Stage III: Transnational interconnected grid

The transnational offshore grid is implemented step by step. The planned lines are built. Where appropriate, wind farms are interconnected and/or connected to different shores.

In 2009, EWEA proposed its 20 Year Offshore Network Development Master Plan, which provided a vision of how to integrate the offshore wind capacities expected for 2020 and 2030 [EWEA, 2009]. This European vision must be taken forward and implemented by the European Commission and the European Network of Transmission System Operators (ENTSO-E), together with a new business model for investing in offshore power grids and interconnectors, which should be rapidly introduced based on a regulated rate of return for new investments.

TABLE 2: COMBINED SOLUTIONS FOR OFFSHORE WIND CONNECTION AND INTERCONNECTION

Project	Description	Countries	Wind power capacity near hub (MW)	Line capacity (MW)		Approximate time in operation
				Capacity MW	Lenghts km	
a. Kriegers Flak	Connecting 1,600 MW wind capacity offshore at the Kriegers Flak location in the Baltic Sea and interconnecting DK, DE and SE (at a later stage)	Denmark Germany Sweden	1,600	Three legged solution 600/600/ 2,200	Threelegged solution < 100	2016
b. Cobra	Interconnector between DK and NL potentially serving wind farms in German EEZ	Denmark The Netherlands	Not defined	700	275	2016
c. Nordbalt – S Midsjöbank	Interconnector between Sweden and Lithuania	Sweden Lithuania	1,000	1,000	350	2016
d. Moray Firth Hub	Connecting Shetland and Scotland, and wind farms in Moray Firth. Although not interconnecting different MS, from technical point of view comparable to combined solutions as mentioned above	UK	2,500	600	340	2014
e. Super node	Technical concept for transmission hub as part of offshore supergrid	UK Germany Norway	4,000	4 x 2,400	Hub concept	Undefined

a: See literature ref. [KF, 2010]
b: Energinet.dk and Tennet
c: E.ON Climate and Renewables
d: Scottish Hydro-Electric Transmission Ltd.
e: Mainstream Renewable Power. www.mainstreamrp.com

At European level, the possibilities for the grid layout are being assessed by ENTSO-E and within the European wind industry (for example the OffshoreGrid project).

Table 2 discusses several ongoing offshore grid planning efforts that are at different stages – mainly undertaken in cooperation between national TSOs. They all consider combined solutions for wind connection and interconnection between power system areas. In principle such initiatives are potential modules for the future transnational offshore Supergrid. In all cases HVDC technology is considered. Several of the listed initiatives are eligible for a grant from the European EERP plan[11]. Despite the variety of projects, all the initiatives listed in Table 2 encounter the benefits and drivers listed below and have the same regulatory, technical, regulatory and planning issues to overcome, as described in the next few sections.

4.2 Technical issues

The status and future of HVDC transmission technology

HVDC transmission technology is an attractive option for the future offshore grid because it offers the controllability needed to optimally share the network in order to transmit wind power and provide a highway for electricity trade both within and between different synchronous zones. Moreover, HVDC cables, because they can be run underground, can run deeper inside onshore AC grids, avoiding the need for onshore reinforcements close to the coast.

High voltage DC comes in two main versions. The classic version of HVDC, with Line Commutated Converters[12] (HVDC LCC), is mainly used today for long distance bulk point to point transport, including applications where only a submarine cable can be used – as is the case in offshore interconnectors between two countries. A more recent version is the HVDC Voltage Source Converter (HVDC VSC)

[11] European Economic Recovery Plan 2010-2013
[12] Classic HVDC is also referred to as HVDC CSC (Current Source Converter)

technology with the following typical characteristics which make it particularly attractive for use in an offshore meshed grid:

- Just like HVDC classic, the VSC technology is more suited for long distances (up to 600 km) than AC.
- The converter stations are more compact than for LCC technology, with beneficial effects for structures like offshore platforms.
- The technology is suitable for use in multi-terminal configuration, allowing a staged development of meshed networks with all the related benefits.
- The technology enables active and reactive power to be controlled independently, with all the related benefits such as inherent capability to provide dynamic support to AC grids; it can be connected to weak onshore grids and can provide black start and support system recovery in case of faults.

HVDC technologies are more expensive but have less energy losses than HVAC, which make them competitive for distances longer than 100 km.

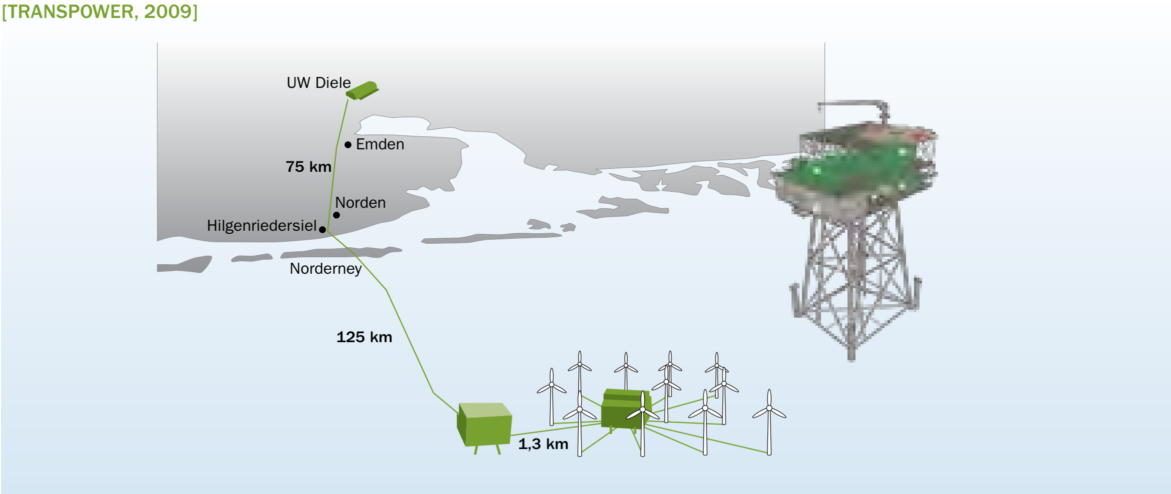
ABB, Siemens and Areva presently offer HVDC VSC technology. ABB uses the brand name HVDC Light, whereas Siemens call it HVDC Plus. The technologies are not identical, and efforts are needed to make them compatible and jointly operable, when used together in the grid. For that purpose, two major conceptual decisions have to be taken: to agree and standardise the DC working voltage levels and to agree on the largest possible plug and play boundary.

An important step in the implementation of HVDC VSC offshore is the Borwin1 project of the German TSO Transpower, to be commissioned by ABB in 2011. This so-called HVDC Light transmission system connects a 400 MW offshore wind plant (Bard Offshore 1) to an onshore transmission station on the German mainland, over a total distance of 200 km of which 125 km are offshore (Figure 3).

Operational aspects of offshore grids

The principal operational task in the offshore grid is the scheduling of the HVDC lines for the predicted amounts of wind power and the nominated amounts of power for trade, and operating and maintaining the grid in a secure and equitable way, granting fair access to the connected parties. The operation of the offshore grid, however, is an integral part of the operation of the overall interconnected European grid, and extremely good coordination is required between the various connected power systems. This is a challenging task for the newly formed ENTSO-E, which has established a sub-group to deal with offshore grids.

FIGURE 3: THE 200 KM HVDC-VSC BORWIN1 CONNECTOR (150 KV) LINKING THE BARD OFFSHORE 1 PROJECT TO THE ONSHORE SUBSTATION DIELE IN GERMAN. ALSO SHOWN IS THE OFFSHORE PLATFORM WITH THE OFFSHORE AC/DC CONVERSION EQUIPMENT [TRANSPOWER, 2009]



4.3 Policy issues

Policy issues at European level

The European policy framework that covers transmission upgrades implicitly covers offshore transmission as well. However, the possibility of building a European offshore grid is facing unprecedented challenges:

- The absence of regulatory frameworks in a market characterised by different regulatory frameworks
- The joint planning of transmission and wind power development and the associated financial risks
- The technological challenges: the deployment of a novel technology (HVDC VSC) in harsh environmental conditions and the associated need for R&D support

Policy issues at regional level (North Sea Countries' Offshore Grid Initiative)

Regional initiatives involving the national political level are crucial for putting European policy into practice and providing cooperation and coordination in order to facilitate the actual developments. At the end of 2008, the Belgian Minister of Energy proposed starting to cooperate on offshore wind and electricity infrastructure within the Pentalateral Energy Forum, an initiative by which governments, TSOs and the system regulators of five countries (Belgium, Germany, France, Luxembourg and the Netherlands) have been working successfully together since 2005 to improve their cooperation in the field of energy. By the end of 2009, the proposal had evolved into a political initiative with the ten countries around the North and Irish Seas (Belgium, France, the Netherlands, Luxembourg, Germany, the UK, Ireland, Denmark, Sweden and Norway). The North Seas Countries' Offshore Grid Initiative (NSCOGI) aims to have the different countries work together to coordinate offshore wind and infrastructure developments. More specifically, it is targeted at achieving a common political and regulatory basis for offshore infrastructure development within the region. A political declaration was signed in December 2009, and the objective is to sign a common Memorandum of Understanding (MoU) between all parties at the end of 2010. From 2011 onwards, the actors in the NSCOGI will start implementing their goals as set out in this MoU.

4.4 Regulatory aspects

The crucial question is 'how to prime the pump' for the offshore grid. The European Commission is best placed to initiate the essential steps, and has announced it will table a blueprint for offshore development by the end of 2010. The NSCOGI is also well placed to work out practical common solutions on policy and regulatory level, as it includes governments, TSOs and regulators.

At present, there are barriers in the electricity market in Europe that hamper an efficient combination of trade and offshore wind power transmission via a transnational offshore grid:

- Differing regulatory regimes and market mechanisms in the countries involved
- A lack of proper rules with respect to priority feed-in for wind power versus nomination of day-ahead trade

Legal and regulatory frameworks need to be established that enable an efficient use of the different lines of the offshore grid in all its stages. In order to ensure an efficient allocation of the interconnectors for cross-border trade, they should be allocated directly to the market via implicit auction (see page 116).

4.5 Planning

Onshore reinforcements related to offshore deployment

The offshore grid cannot be conceived in an isolated way from the rest of the network. Such a grid needs to be developed in order to promote trade and the connection of offshore renewable power, and this development has to take place as part of the European network planning carried out by the joint European TSOs (see 4.5.2.). The practical consequence in the short to medium term is that onshore reinforcements have to be implemented on specific transmission corridors and lines. The exact locations of connection points, corridors and lines to be upgraded need to be studied and identified. The OffshoreGrid project identified a substantial shortage of capacity on onshore connection points for the envisaged offshore capacities in 2030. This implies that there is a significant shortage of transmission capacity in coastal areas.

One of the first studies that looked into the need for onshore reinforcements at European level is TradeWind. On the basis of the wind power scenarios, the study has identified upgrades that would significantly alleviate the congestion in the European grid, for wind power scenarios up to 2030. The EWIS study also looked at the need for onshore reinforcement in Europe, but its timeframe is limited to 2015, by which time the development of offshore wind will only to a limited extent trigger solutions and transmission upgrade levels at European level.

Apart from upgrading the onshore transmission network, other technical issues have to be addressed such as the planning, operation and control of the various interconnected power systems associated with the addition of multiple HVDC terminals, and the handling of the regionally distributed power flows from offshore.

ENTSO-E North Sea regional group

Three of the working groups in ENTSO-E's System Development Committee are specifically dealing with offshore transmission infrastructure. In the regional groups, there is the North Sea group and the Baltic Sea group. They are responsible for the cooperation between the TSOs in these regions and the coordination of power system planning. To get a long-term vision, ENTSO-E established a working group for 2050 and the Supergrid which looks at the future needs for a trans-European Supergrid. The working group will draw up a programme of technical, regulatory, planning, policy and financial studies by 2011, and will coordinate these studies in the following years.

Joint planning of wind power and transmission and the associated risks

The next decades will bring huge investments in offshore wind energy and offshore electricity infrastructure. In order to use these as effectively as possible, careful planning is essential. Four topics are crucial:

- Location: First of all, offshore wind farms need to be planned as close as possible to where they can be connected, in areas with a good wind climate. Furthermore, international cooperation is necessary to maximise opportunities for sharing power across borders and for linking wind power to interconnectors.
- Timing: Joint planning of wind power plants and transmission leads to risks of stranded investments. Proper coordination is crucial, and regulators should encourage this. Furthermore, adequate maritime spatial planning should be made as soon as possible in order to speed up and facilitate permitting procedures and to reduce development risks.
- Technical: The onshore grid should be reinforced where necessary in order to accommodate the large capacities of offshore wind farms. The technology should be ready when it is needed, and planning should be adjusted to the technology available (e.g. when large wind farms are built far from shore, cables and components with larger capacities should be available).
- Supply chain: The availability of ports, vessels, cranes, skilled workers etc. should be coordinated internationally and followed up more closely. Government plans and targets should allow for a secure investment framework in the long term (e.g. not requiring several GW to be installed every year until 2020 and stopping afterwards).

Photo: Javier Arcenillas

5 COSTS OF TRANSMISSION UPGRADES AND WHO PAYS FOR WHAT

5.1 Cost estimates

The “transmission cost” is the additional costs of integrating wind power into the transmission system. Several national and international studies are looking into these costs, quantifying the grid extension measures and the associated costs caused by additional generation and demand in general, and by wind power production in particular. The report [Holttinen, 2009] gives an overview of the results of the relevant study. The analyses are based on load flow simulations for the corresponding national transmission and distribution grids and take the different wind energy integration scenarios into account using the existing, planned and future sites.

The cost of grid reinforcements needed for wind power integration is very dependent on where the wind power plants are located relative to load and grid infrastructure. It is not surprising that these costs vary a good deal from country to country and cannot be directly compared because of the different local circumstances. The studies found that the cost normalised over wind power capacity ranges from €0-270/kW. Normalised over wind energy production, the costs are in the range of €0.1-5/MWh. For wind energy penetration of up to 30% they are typically approximately 10% of wind energy generation costs (around the same level as the additional balancing costs needed for reserves in the system in order to accommodate wind power). Just like the additional balancing costs, the network costs increase with the wind penetration level, but unlike the additional balancing costs, the cost increase is not parallel to the increasing wind penetration. There can be one-off, very high cost reinforcements due to a variety of factors, for example related to social acceptance issues which may cause underground cabling for parts of the transmission line with much higher costs than foreseen.

The studies either allocate the total extra cost or part of it to wind power. When they only allocate part of it, it is because most grid reinforcements and new transmission lines benefit all consumers and power producers, and thus can be used for many purposes, such as increased reliability and/or increased trading.

Grid reinforcements should be compared to the possibility of controlling wind output or altering the way other types of generation are operated. The latter might make better economic sense, for example in cases where grid adequacy is insufficient during only part of the time because of specific production and load situations.

Finally, when considerable grid reinforcements are necessary, the most cost effective solution for transmission planning would be to plan and expand the transmission network for the final amount of wind power in the system rather than planning one phase of wind power growth at a time.

The national transmission upgrade cost figures tend to exclude the costs for improving interconnection between the Member States. These interconnection costs have been investigated in European studies, such as TradeWind and EWIS, as mentioned previously with scenarios up to 2030.

TABLE 3: GRID UPGRADE COSTS FROM SELECTED NATIONAL SYSTEM STUDIES [HOLTTINEN, 2009]

Country	Grid upgrade costs	Installed wind power capacity	Remarks
	€/kW	GW	
Portugal	53 – 100	5.1	Only additional costs for wind power
The Netherlands	60 – 110	6.0	Specifically offshore wind
United Kingdom	45 – 100	8.0	
United Kingdom	85 – 162	26.0	20% wind power penetration
Germany	100	36.0	Dena 1 study
Ireland	154	6.6	Cost is for all renewables, wind is 90%. The cost adds 1-2% to electricity price.
Denmark	270	3	Assuming that 40% of upgrade cost is attributed to wind.

EWIS calculated the costs of the network developments currently planned in order to accommodate the additional wind power between 2008 and 2015. It found they range from €25/kW for immediate measures to €121/kW wind for measures that will accommodate the 'Optimistic' scenario in the short and longer term. The €121/kW figure represents around €4/MWh, which is similar to the additional operational costs for addressing the added variability by wind power and is a small proportion of the overall benefits of wind generation. The EWIS values are well in the range of the findings of the studies listed in Table 3.

5.2 Allocating grid infrastructure costs

There is no doubt that transmission and distribution infrastructure will have to be extended and reinforced in most of the EU countries when large amounts of wind power are connected. It is also clear that a far better interconnected power system is needed in Europe, if we are ever to achieve a well-functioning single market for electricity and real competition, to the benefit of consumers. However, these adaptations are needed not only to accommodate wind power, but also to connect other sources to meet the rapidly growing European electricity demand and trade flows. The need to extend and reinforce the existing grid infrastructure is critical. Changes in generation and load at one point in the grid can cause changes throughout the system, which may lead to power congestion. It is not possible to identify one (new) point of generation as the single cause of such difficulties, other than it being 'the straw that broke the camel's back'. Therefore, the allocation of costs necessary to accommodate a single new generation plant to that plant only (for example, a new wind farm) should be avoided.

Also, the discussion on financing new interconnectors should be placed in the broader context of the development of an internal electricity market, thereby not relating the benefits of grid development to individual projects or technologies. Infrastructure projects are natural monopolies and should be treated as such. Grid development benefits all producers and consumers and, consequently, its costs and benefits should be socialised.

Photo: Thinkstock

6 MORE ACTIVE DISTRIBUTION NETWORKS

The amount of distributed (embedded) generation (renewable energy technologies and CHP) is growing rapidly at distribution level. Distribution networks are less robust than transmission networks and their reliability – because of their radial configuration - decreases as the voltage level goes down. Moreover, there is very little so-called "active" management of distribution networks. Rather, they are designed and configured on the basis of extreme combinations of load and ambient temperatures, (which reduce the capacity of overhead lines). The addition of wind power to these networks creates new loading situations, for example changed power flow directions which affect the operation of network control and protection equipment, and mean design and operational practices need changing. A very important issue here is the increased necessity for active voltage management.

Networks using new ICT technology and strategies for active management are envisaged as a possible next step from the current passive distribution networks and offer the best way to initially facilitate DG in a liberalised market. They are based on two broad principles, namely (a) high connectivity providing multiple links between supply and demand and (b) providing interaction with the consumer or more generally, with the grid users that both consume and produce electricity, the so-called 'prosumers'.

The co-ordinated, intelligent control and integration of a DG grid is the subject of various experiments carried out by the Danish TSO, Energinet. The project called "the Cell Controller Pilot Project" [Martensen, 2009] develops the controllers, data acquisition, commands, and communication infrastructure for a so-called pilot "Cell" consisting of existing distributed assets including wind turbines, bio-energy plants and responsive loads. This kind of experiment is part of the development towards power systems where implementation of renewable generation together with sufficient intelligent control near the consumers at distribution level enables the uptake of large shares of distributed generation and an enhancement of system security. However, costs should be compared to the implementation of renewables at transmission level when more economic ways of balancing are available and can be exploited.

7 A HOLISTIC VIEW OF FUTURE NETWORK DEVELOPMENT: SMART GRIDS

With increased penetration levels of distributed generation, including large-scale deployment of wind power both at transmission and distribution level, the distribution networks can no longer be considered a "passive appendage" to the transmission network. For the future very high shares of renewable energy, the entire transmission and distribution system will have to be designed and operated as an integrated unit. It will be necessary to deploy innovative and effective measures such as 'smart grids', also termed 'active networks', 'intelligent grids' or 'intelligent networks', in order to maintain supply and demand in balance in networks with a large amount of renewables. Managing such a configuration involves several different parties, and is a complex task. An important research task for the future is the investigation of the use of controlled, dynamic loads to contribute to network services such as frequency response.


Photo: iStock

8 SUMMARY

Upgrading the European network infrastructure at transmission and distribution level is not only vital for the functioning of the emerging single electricity market in Europe, but is also a fundamental step on the way to large-scale wind power integration. Better interconnected networks bring great benefits for distributed renewable power by aggregating dispersed (uncorrelated) generation, which leads to continental smoothing, greater predictability and an increased capacity credit.

Significant barriers to a truly pan-European grid include the public's reluctance to accept new transmission lines (causing very long lead times), high costs and financing needs and the absence of proper cost recovery methods for multi-state lines.

Expanding and reinforcing the European transmission grid will help wind reach higher penetration levels, and in a scenario with substantial amounts of wind power, the additional costs of wind power (higher installed costs, increased balancing, and network upgrade) could be outweighed by the benefits, depending on the cost of conventional fossil fuels. The expected continuing decrease in wind power generation costs is an important factor. The economic benefits of wind become larger when the social, health and environmental benefits of CO_2 emission reductions are taken into account. European studies like TradeWind and EWIS have quantified the large benefits of increasing interconnection capacities for all grid users, and have identified specific grid corridors that can be reinforced to support the implementation of large-scale wind power in Europe. For its 2030 wind and transmission scenario, TradeWind estimates a yearly reduction of €1,500 million in the total operational costs of power generation as a result of targeted upgrade of interconnection.

Grid development benefits all producers and consumers and, consequently, its costs and benefits should be socialised.

There is a range of methods to be implemented in the short term in order to optimise the utilisation of the existing infrastructure and transmission corridors, meaning the European transmission capacity can be swiftly improved in order to uptake the fast growing wind power installed capacity, maintaining high level of system security. Dynamic line rating and rewiring with high-temperature conductors offer the possibility to significantly increase the transmission corridors' available capacity. A range of power flow technologies (FACTS) and improved operational strategies are suitable immediate options to further optimise the utilisation of the existing network.

Transnational offshore grids should be constructed to access the huge European offshore resource. The economic value of an offshore grid in Northern Europe justifies investments in the order of €20-30 billion up to 2030 not only to tap into the potential offshore, but also to increase cross-border trading in Europe. A step by step approach is recommended, starting from TSOs' existing plans and gradually moving to a meshed network. The TYNDP must play a crucial role here by providing a long-term planning vision for European grid infrastructure.

Demonstration projects connecting offshore wind farms to two or three countries should be built to test concepts and to develop optimal technical and regulatory solutions. The consequences for the onshore grid in terms of reinforcement in the coastal zones should be considered at an early stage. Accelerated development and standardisation of transmission technology, more specifically multi-terminal HVDC VSC is necessary in order to achieve a timely deployment. Neither the proper regulatory framework, nor the legal conditions and incentives that could encourage initiatives in multistate transmission are in place. They must be developed in a joint effort by Member States, the European Commission, European energy regulators, TSOs and the relevant stakeholders.

Taking into account future very high shares of wind power and other renewable generation in general, the entire transmission and distribution system has to be designed and operated as an integrated, flexible unit, in order to optimally manage the distributed generation together with a more responsive demand side. Innovative and effective measures need to be deployed, such as 'smart grids', also termed 'active networks', 'intelligent grids' or 'intelligent networks', and assisted with monitoring and control methods that allow high concentrations of variable generation to be managed, especially at distribution level. An important research task for the future is the investigation of the use of controlled, dynamic loads to contribute to network services such as frequency response.

5 ELECTRICITY MARKET DESIGN

Photo: iStock

1 INTRODUCTION

This chapter considers the characteristics and mechanisms in European power markets which have an essential influence on the process of wind power integration. In addition to liberalisation and the degree of market integration, these include the possibilities of trading reserves and operating the power exchanges closer to real time. Furthermore, current developments in the European electricity markets that are relevant to the integration process are discussed, indicating roles for key players, legislative processes and providing recommendations for facilitating wind power's integration.

Photo: Detlev Gehring-SST

2 BARRIERS TO INTEGRATING WIND POWER INTO THE POWER MARKET

A set of market rules for facilitating wind power's efficient market integration needs to take the characteristic properties of wind energy into account, namely:

- Distributed and continental: Wind power is a continental resource, related to large meteorological phenomena (on the scale of 1,000 km) exploited at geographically dispersed sites. Wind resource availability has a low geographical correlation.
- Predictability: The quality of wind power forecasts increases with a shorter forecast horizon and over a larger area. Along with each forecast, confidence margins can be supplied in order to schedule reserves to compensate for potential forecast errors (see Vol. 2 and 3).
- Variability: The characteristic significant wind power variations are in the range of 15 minutes to a few days. Wind speed is correlated for short distances but not for long distances - over 1,000 kilometres (Chapter 2).
- Low marginal costs: Wind energy requires no fuel. Therefore, its marginal cost is very low and electricity is produced without green house gas emissions. Consequently, wind power should be used whenever wind is available. At times of low demand, wind power will have to compete with power from bulk load plants, which often cannot adapt their output to fast changing set points.

Integrating wind power with the above characteristics is easier in an electricity system that has the following characteristics:

- System spanning a large geographical area enabling the variability to be smoothened and predictability and capacity value to be maximised.

- Sufficient internal network capacity[1] providing access to distributed generation and balancing resources, also enabling the aggregation of dispersed wind power.
- Operating close to real time to improve wind power forecast accuracy and minimise uncertainty and the additional balancing costs.
- Availability of a multitude of balancing resources (facilitated by 'the first point' above).
- Availability of responsive demand and storage, e.g. in the form of hydro power.

European markets are in the process of being liberalised while enhancing sustainability, competitiveness and security of supply. Wind power integration would be best supported by a power market characterised by the following aspects:

- Flexibility of the rescheduling of dispatch decisions (time dimension) supported by functioning day-ahead, intraday and balancing markets.
- Flexibility of cross-border exchange supported by sufficient cross border capacities, efficient trading rules and functioning day-ahead, intraday and balancing markets.

A high flexibility of rescheduling of dispatch decisions will be required when demand and generation are subject to frequent and significant unexpected changes during the day. Flexibility is provided by generation units with short activation times, e.g. combined cycle gas turbine units or reservoir hydro units.

Flexibility of cross-border exchange is beneficial for market harmonisation. With an increasing share of variable generation, flexible cross-border exchange mechanisms contribute to optimising the dispatch of electricity at international rather than national level. The efficiency of cross-border exchange also depends strongly on the mechanism for capacity allocation. Ideally, capacity should be allocated in an implicit way via market coupling mechanisms rather than by an explicit auction.

Traditionally, market rules in Europe were developed for nationally contained power systems with largely thermal and centrally dispatched generation units. The difficulties wind energy faces in gaining market access are to a large extent due to the fact that existing markets do not have the characteristics mentioned in the five bullet points at the beginning of this page. Significant barriers include the level of market access for small and distributed wind power generators, and the lack of information about spot market prices in alternative neighbouring markets during the allocation of cross-border capacity. Barriers faced by small generators may be overcome by aggregation, and the lack of information from alternative markets may be overcome by the coupling of national markets with implicit capacity allocation. Examples for market coupling are the NordPool market in the Nordic countries and the 'Pentalateral' market coupling between the Benelux, France and Germany.

[1] In a large system like Europe, the internal network includes the cross-border links between Member States.


Photo: Thinkstock

3 DEVELOPMENTS IN THE EUROPEAN ELECTRICITY MARKET

3.1 Liberalised national markets

The reason for liberalising the European electricity market is to create a competitive and truly integrated electricity market in the European Union. The first years of liberalisation were characterised by the opening of national markets for competition. As ownership unbundling of generation, transmission and distribution progresses, utility companies in their traditional form will cease to exist. The public obligation of the vertically integrated utility - to keep the lights on by controlling generation, transport and distribution - is no longer valid, and gives way to self-dispatch mechanisms. This means that while the transmission network is controlled by the TSO, the power plants are dispatched by the market participants.

In order to guarantee network security, self-dispatch will be accompanied by balancing obligations. Each user of the transmission grid will be responsible for keeping his activities neutral with respect to the grid, that is, maintaining the equilibrium of injections to and withdrawals from the transmission system for its portfolio. As a consequence, in a liberalised market, grid users present the TSO with a balanced programme on a day-ahead basis, with a time resolution of between 15 minutes and one hour. Imbalances (violations of the generation-load equilibrium of a particular portfolio) are settled ex-post with the TSO at an imbalance tariff that is unfavourable compared to market prices. The TSO keeps the responsibility for the balance of its control zone, contributing thus to overall system security. The means to do so, namely the reserve power plants, are contracted from market participants able to provide fast regulating power.

3.2 European integration assisted by interconnection

Before 2006, all markets in Europe were national, with the exception of the Nordic market. These markets were characterised by one or a few dominant power producers that had emerged from the former utilities which owned a major share of the generation and transmission capacity. New market entrants that owned generation capacity abroad faced the difficulty of transporting variable amounts of power over the borders.

An integrated power market should be made up of different countries. In a perfect market, the market prices between these countries should only differ when the interconnector capacity between the countries is insufficient. Interconnectors would be used based on the evolution of prices in the different markets. In the past, allocation of interconnector capacity was not market-based, whereas now mechanisms in Europe are becoming increasingly market-based, mainly through auctions. Most auctions are explicit, meaning that in order to offer energy on a foreign spot market, a market participant has to buy a cross-border transfer capacity at the capacity auction and energy at the concerned spot markets separately.

In order for a power market to be truly competitive, sufficient transmission capacity is required between the relevant markets. Moreover, the legal and regulatory framework must enable an efficient use of interconnectors between participating countries. This is made possible by market coupling and splitting, leading to an implicit allocation of interconnector capacity, which is when bids and offers from different countries are combined in order to establish a common market price for the region. Whenever an interconnector is congested, the prices on either side cannot converge further, and the price difference represents the value of the interconnector for trade. Such implicit auctioning ensures that interconnector capacity is used efficiently.

In the last few years, the European integration of power markets has accelerated thanks to several initiatives. First, the Regional Initiatives of the European Regulators' Group for Electricity and Gas (ERGEG) pursued the development of seven regional electricity markets, each made up of several national markets. The larger countries such as Germany and France participate in several regional markets. Consequently, a market player in one of those countries can choose any of the available market regions for every bid or offer. In practice, this is likely to align prices in the different regional markets.

However, the most concrete steps towards regional markets were taken in the creation of the NordPool market and the Pentalateral market between Benelux, France and Germany. Moreover, in 2007, Germany joined the NordPool day-ahead market. A further market coupling between Germany and Denmark operated by EMCC[2] was put in place at the end of 2009. The Pentalateral Energy Forum launched the so-called "North Seas Countries' Offshore Grid Initiative" in 2010. Other examples of regional integration are the Irish All-Island market and the Iberian MIBEL.

Ongoing market integration across Europe could provide a further building block for a future power system characterised by flexibility and dynamic electricity markets, where an increased number of market participants, including the demand side, respond to price signals, facilitating competition and better integration of wind power and other variable renewables.

[2] EMCC: European Market Coupling Company.

3.3 Legal framework for further liberalisation of the European electricity market

The movement towards liberalised markets is being boosted by a thorough legislative process at European level. An important step was taken by the adoption of the Third Liberalisation Package in 2009. In this package, the European role of network operators was spelt out more clearly in the obligation to create an umbrella organisation - ENTSO-E (European Network for Transmission System Operators for Electricity) - with a clear mandate for transmission planning and coordinated operation at European level.

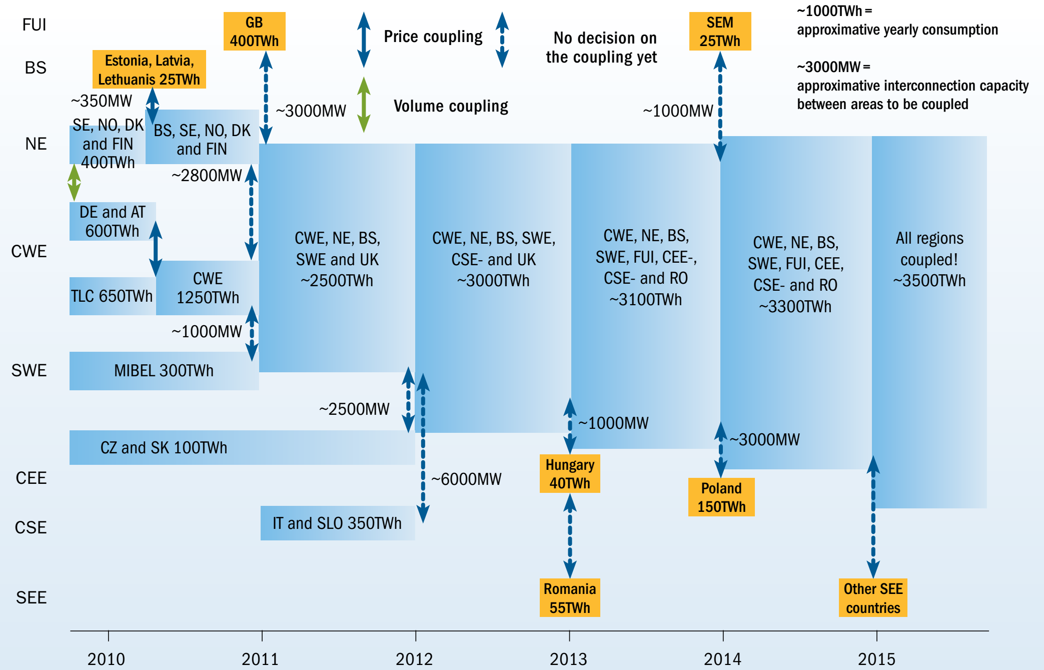
The establishment of ENTSO-E took place in 2009 and is expected to lead to an increase in transmission capacity, alleviating congestion in the European grid and ultimately bringing about lower power prices.

Equally, within the package of regulatory measures, it was decided to reinforce the European role of the energy regulators by creating a European Agency for Energy Regulation, ACER. This Agency is to initiate and oversee the process of creating appropriate codes for network and market functioning in the liberalised power market.

At the time of writing, this process had just started with work on a first "pilot" network code on grid connection requirements (see Chapter 2).

Considering the variable degree of progress in different market regions, the European Commission launched a roadmap and target model for the convergence of Regional Initiatives to a single market. A possible sequence of European market coupling to be accomplished by 2015 has been proposed by the European Forum for Electricity Regulation (Florence Forum) as illustrated in Figure 1.

FIGURE 1: ROADMAP PROPOSED BY THE EUROPEAN FORUM FOR ELECTRICITY REGULATION TOWARDS A SINGLE MARKET



Possible sequence of European market coupling (please note that the sequence and timing is only indicative and does not represent any agreed position of the PCG)

Source: Project Coordination Group (PCG) slide, 17th Florence Forum, 10&11 December 2009

4 WIND POWER IN THE EUROPEAN INTERNAL ELECTRICITY MARKET

4.1 Current market rules in EU Member States

There is a high degree of diversity in the adequacy of market characteristics for wind power across the EU. Some observations are given here based on an analysis in [TradeWind, 2009]:

- Most countries in the EU, with the exception of Slovenia and Malta, have liberalised their power markets. Switzerland, Greece and Hungary are on the way to liberalisation.
- Functioning day-ahead power markets exist in most countries, although some have low liquidity. In terms of trading on the spot market, high shares are only observed in the Nordic countries and Spain. In Spain, the volume traded on the day-ahead market is up to 90% of energy consumption. On the Nordic day-ahead market, the volume traded in 2009 represented about 72% of overall consumption. On the other day-ahead markets this share was mostly well below 20%.
- Intraday markets exist in several countries (including France, Belgium, Germany, The Netherlands, Spain, and the Nordic countries), but in most cases these markets are young and suffer from very low liquidity. These markets are used for final fine-tuning of portfolios shortly before delivery. Therefore, the volumes traded on these markets are much lower than on the day-ahead markets, typically, a few percent of consumption.
- The overall organisation of balancing markets is fairly similar in many countries; nevertheless significant differences do exist on a more detailed level. On the other hand, cross-border balancing markets do not yet exist.

- Wind power support schemes are different in the various Member States: feed-in tariffs are most common, followed by green certificates and premium systems. However, substantial differences exist as to how the types of support schemes are used by individual Member States, such as feed-in tariffs, premium mechanisms, tenders or green certificate schemes.
- In most countries wind power is prioritised in dispatch. Only in a few countries (Denmark and Finland) is balancing the responsibility of the generation plant owners.
- In most countries, wind power is not penalised if the forecasted production is not fulfilled, but exceptions do exist.
- Explicit auctioning is the most common way of allocating cross-border capacities (yearly, monthly, daily). Day-ahead market couplings exist in the Nordic countries, between the Netherlands, Belgium and France, and internally in Italy. It was decided in June 2010 to establish an intraday market coupling between the Netherlands, Belgium and the Nordic countries, operational as of November 2010.

4.2 Economic benefits of proper market rules for wind power integration in Europe

The mechanisms that governed the power market in the past have created barriers for the large-scale implementation of variable renewables in general and wind power in particular. The ongoing market reform processes at European level present an opportunity to develop and introduce market mechanisms and rules that take into account the specific properties of variable renewables. Different market scenarios have been analysed in the TradeWind project [TradeWind, 2009] on their benefits for the integration of wind power. The scenarios were characterised by two dimensions:

- Time constant of the market (flexibility).
- Geographical size (degree and flexibility of cross border exchange) of the market area.

Looking ahead to the 2020 and 2030 scenarios (Chapter 4), the macro-economic benefits of a properly functioning market in electricity are:

- Intra-day rescheduling of generators and the application of intra-day wind power forecasting reduces reserve requirements and results in savings in the order of €250 million per year.
- Intraday rescheduling of power exchange (international trade) leads to low system costs and stable prices, resulting in savings of €1-2 billion per year.

The availability of network infrastructure to assist the developing internal market is vital. The availability of sufficient interconnection capacity to enable prices to converge, results in savings in the order of €1.5 billion per year for TradeWind's 2030 scenario.

Wind power curtailment and load shedding would not exist if the market were well designed. An international exchange of reserves is not the first market design priority because the need for reserve power would be kept low if intra-day rescheduling of power exchange and by intra-day rescheduling of unit commitment and dispatch of units were effective. The main benefit of exchanging reserve power could consist of possible investments savings in flexible power plants due to reserves being shared across borders.

5 SUMMARY

The lack of properly functioning markets is a barrier to the integration of wind power. Barriers include the low level of market access for small and distributed wind power generators and the lack of information about spot market prices in alternative neighbouring markets during the allocation of cross-border capacity. In order for a power market to be truly competitive, sufficient transmission capacity is required between the market regions.

Further market integration and the establishment of intra-day markets for balancing and cross border trade are of key importance for power market efficiency in Europe when integrating large amounts of wind power. In this way, the market will respond more adequately to the characteristic properties of wind energy.

The adoption of the third Liberalisation Package in 2009 is a very important step towards European market reform, encouraging much more competition and a higher uptake of renewables. One especially useful element of the Package is its clear list of tasks at European level for TSOs and energy. Creating network codes in consultation with the market stakeholders should help establish market rules that put variable renewables and wind power on a level playing field with other forms of generation.

The European Commission has decided, along with the European energy regulators and other stakeholders, to develop a target model and roadmap for the integration of electricity markets. The outcome of this work shall directly feed into a future framework guideline and subsequent network codes on congestion management and capacity allocation. The overall aim is to implement a generic target model and roadmap across Europe by 2015 at the latest and to ensure the convergence of all regional markets into one single European market.

The ongoing market integration across Europe - notably the establishment of regional markets - constitutes, in principle, a suitable building block for flexible and dynamic electricity markets. Markets in which an increased number of market participants, including the demand side, respond to prices, facilitating the integration of wind and other renewables. Ongoing initiatives such as the NordPool market, the Pentalateral Energy Forum, the Irish All-Island market and the Iberian MIBEL are all instrumental to the uptake of more variable renewables. The “North Seas Countries’ Offshore Grid Initiative” offers the means, in the short-term, to progress towards the creation of a North Sea market bringing offshore wind power online.

A real market capable of integrating wind power yields significant macro-economic benefits through the reduction of the total operational cost of power generation. Intra-day rescheduling of generators and application of intra-day wind power forecasting for low reserve requirements results in savings up to €250 million per year. Rescheduling of power exchange trade on an international level results in savings of €1-2 billion per year.

6 THE MERIT ORDER EFFECT OF LARGE-SCALE WIND INTEGRATION

PÖYRY

1 BACKGROUND

Wind power in the EU has demonstrated impressive growth rates over the last years. One main reason for this has been the development of the European energy and climate policy, constantly supporting renewable energy technologies via growth targets and national support schemes. In 2008, the EU adopted the European Commission's climate and energy package, which included the Renewable Energy Directive (2009/28). This directive sets a 20% EU target for the use of renewable energy sources in 2020. The 20% overall target is broken down into different legally binding national targets.

At national level, plans and policies for the extension of renewable energy, especially for wind energy, are already in place to varying degrees and forms, adding competition to the future European energy market. By 2020 EWEA expects the European Union to produce 540 TWh of additional wind power, with a big share of this coming from large-scale offshore wind.[1] In 2010, Member States are drawing up National Renewable Energy Action Plans detailing the ways in which they are to meet the 2020 targets. The reports will indicate how countries are doing in achieving their targets and policies for the development and support of wind power, encouraging consistent progress. In order to ensure that they continue to support wind power, it is important to demonstrate the benefits of wind power development, not only because it helps meet political targets, but also because wind power boosts energy

[1] The European Wind Energy Association. 2009. Pure Power Wind energy targets for 2020 and 2030.The figure refers to the Pure Power High Scenario: For the EU as a whole, wind energy production would increase from 137 TWh (2008) to 681 TWh (2020) and wind energy's share of total electricity demand would increase from 4.1% in 2008 to 16.7% in 2020.

independence and regional development, while helping reduce greenhouse gas emissions, and electricity prices.

Market dynamics prove that large amounts of wind power lead to significant decreases in the average wholesale power price level (known as the merit order effect). But this only applies as long as wind power reduces the need for conventional capacity, which also depends on the expected power demand. In areas where power demand is not expected to increase very much and in areas where the amount of new deployment of wind power is larger than the increase in power demand, wind energy will replace the most expensive power plants. This will lower the prices in these areas. Hence, the amount the price goes down depends on the energy mix and the marginal technology which will be replaced by wind power investments. In wind and hydro-based systems (like in the Nordic countries), prices decrease slightly more than in thermal based systems. Additionally, the system's connection to neighbouring areas, as well as the availability and use of transmission capacities also impacts the effect wind power has on the price. Therefore, country specific results on the average power price decrease through increased wind power can vary considerably.

Photo: Thinkstock

2 INTRODUCTION

This study aims to analyse the impact of increased wind power share in total electricity production in Europe. The main focus is the merit order effect of increased wind power up to 2020.

The project was carried out in two phases. The first phase consisted of a survey of existing studies covering the merit order effect from the perspective of wind power, and the second phase consisted of a modelling analysis based on Pöyry's power modelling tools and on scenarios defined by EWEA. The ultimate goal was to assess the price effect of wind power on the wholesale power price.

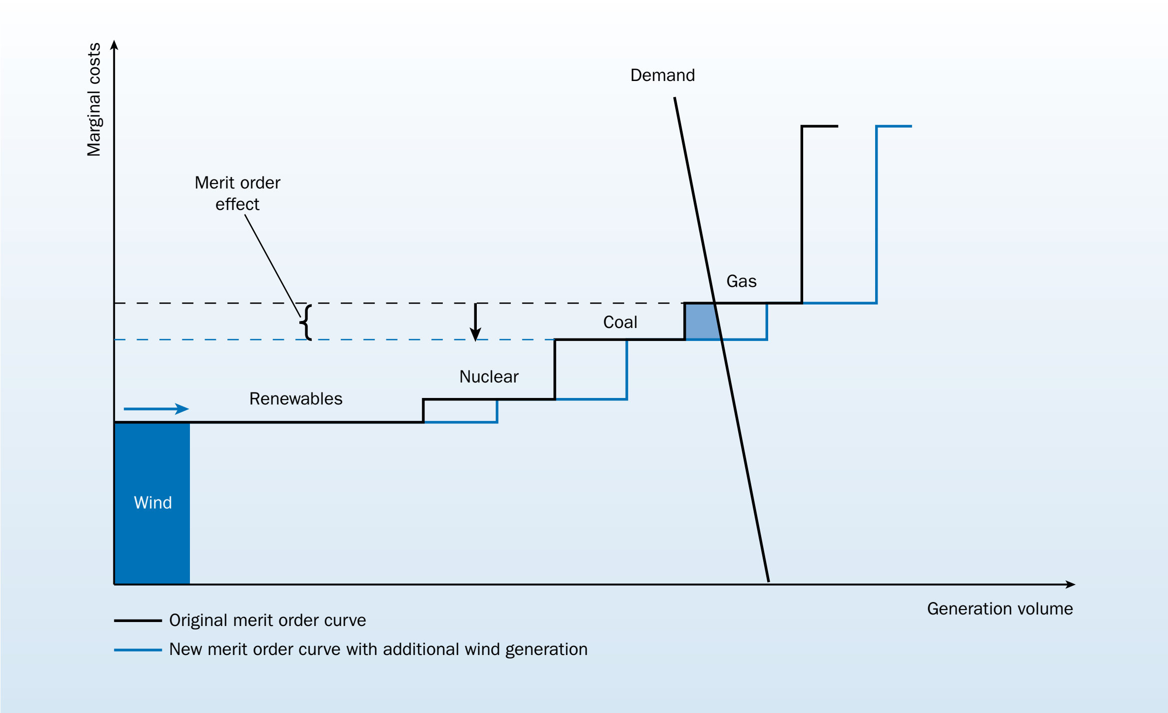
This report presents the results of the second phase of the project, the modelling analysis. The literature survey was presented in a first project report.[2]

In the past, numerous studies on merit order effects have been published. Most of them, however, are single country studies, e.g. for Germany, Spain and Denmark. Consequently, there is a need to estimate the merit order effects at European level in order to estimate the total benefits of reduced power market prices from large-scale wind power development in Europe. This was the aim of the second phase of the project.

The "merit order" principle is a cost optimisation principle, which means that plants with the lowest short-run marginal costs (SRMC) are used first to meet

[2] European Wind Energy Association, 2009, Study on Merit Order Effect of Wind Power, Phase 1: Literature Survey

FIGURE 1: MERIT ORDER EFFECT OF RENEWABLE POWER GENERATION



demand, with more costly plants being brought on-line later if needed. The merit order principle is the guiding principle of an electricity spot market in which the lowest bids will be served first. In case of increased wind power generation, the most expensive conventional power plants might no longer be needed to meet demand. If the short-run marginal costs of wind power are lower than the price of the most expensive conventional plants, the average cost of electricity goes down. This is called the 'merit-order effect' (MOE). It refers to the day-ahead or spot power price and is based on the short-run marginal costs of power generation when investment costs are not included.

Figure 1 shows a supply and demand curve for a power exchange. Bids from wind power enter the supply curve at the lowest price level due to their low marginal cost (blue block on the left of the supply curve). In the above figure, wind is therefore part of the renewable technology step on the left side of the curve which also includes hydro technologies. They will usually enter the merit order curve first, before other conventional technologies come in. The only exception is hydro reservoir power, which could be kept aside in situations of very low power price levels. In the general merit order curve, renewable technologies are followed by nuclear, coal and combined heat and power plants, while gas-fired plants are on the upper side of the supply curve with the highest marginal costs of power production. Furthermore, it is assumed that the electricity demand is very inelastic in the short-term perspective of a spot market.[3] With an increased share of wind power the supply curve is shifted to the right (becoming the new blue curve), resulting in a lower power price. In general, the short-term price of power is expected to be lower during periods with high wind than in periods with low wind. At a given demand, this implies a lower spot price at the power market.

[3] Inelastic demand means that power demand does not significantly increase or decrease to correspond with a fall or rise in the power price. This assumption is realistic in a short-term perspective and reflects short-term bidding behaviour due to the direct relation between the price level and total revenues; an increase in price increases total revenues despite a fall in the quantity demanded.

However, this study investigates not the short-term price effect but the long-term price effects of increased wind power generation. A modelling tool was used to investigate several scenarios for future European power market development up to 2020. The analysis quantified the long-term merit order effect of increased wind power penetration in Europe in 2020; it predicts how the future power market will develop, and what investments will be made. The modelling tool is used to simulate the market's long-term equilibrium. Therefore, the calculated merit order effect is based on the simulated power price levels for 2020. All prices are calculated in regard to the long run marginal costs (LRMC). That means the cost of production is considered as output assuming that all production input, including capital items (plant, equipment, buildings) are obtained at the price levels forecast. This differs from the short run marginal cost consideration described above, which allows only variable production input (labour, materials, fuel and carbon). It assumes costs are fixed and therefore disregards, for example, the equipment and overheads of the producer.

This part describes the main conclusions drawn from modelling analysis. It outlines the main results of the study, and describes the study's methodology and the modelling tool (see page 140). The main findings as to the merit order effect and the volume merit order effect of increased wind power are presented on page 144, and followed by a sensitivity analysis. This analysis quantifies the impact various factors, such as fuel prices and the greenhouse gas reduction target, can have on the merit order effect. Finally, this study's results are compared with the reviewed literature of the first phase of the project. Basic model assumptions and a description of the modelling tool can be found in the Annex.

Although Pöyry AS conducted this project and carried out the modelling analysis, all model and scenario assumptions in terms of data input were defined by EWEA.

2.1 Summary of literature survey

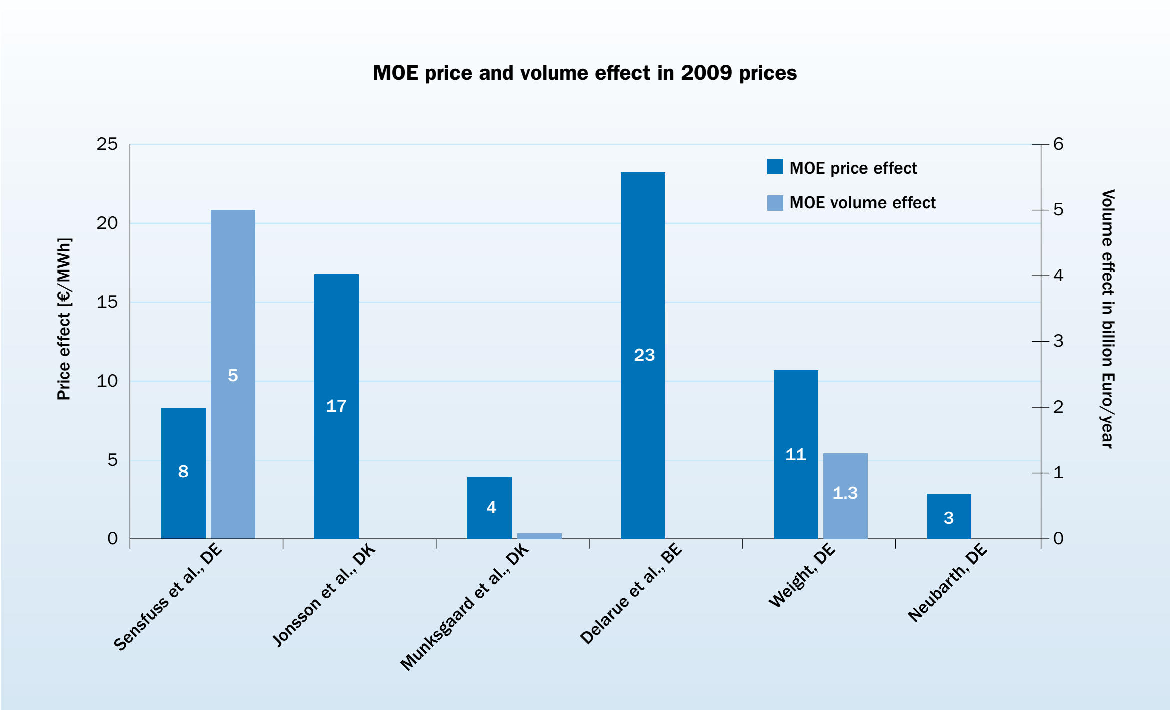
The studies reviewed for the first phase of the project, the literature survey, cover a wide range of aspects concerning the price and merit order effect of increased wind power penetration. Mostly, the studies concentrated on a specific country. Although the studies defined different sets of assumptions they essentially draw similar conclusions. The general conclusion in all of them is that there is a downward movement of wholesale[4]/spot prices, due to increased wind power penetration. Some studies observed instances where the spot price was zero, which could be partly because of wind generation. The papers specified a merit order effect (MOE) ranging from €3-23/MWh, depending on the assumptions they worked from. Moreover, the literature discussed the MOE of increased wind power in terms of the technology replaced by wind and their position in the merit order curve[5]. Finally, only a few of the evaluated literature studies indicated the total amount of savings made due to wind power during a particular year. For Germany, two studies put the savings brought about by increased wind power within a range of €1.3 – 5 billion per year. The Danish volume effect is estimated by one study to have been €0.1 billion in 2006. However, all these figures were very much dependent on assumptions such as the assumed wind penetration level, the power generation mix and the marginal costs of the replaced conventional technologies. Furthermore, the studies only address the merit order effect in regard to short run marginal costs, since they refer to existing or past capacity mixes where investments were fixed. The graph below summarises the findings from the studies reviewed.

One of Pöyry's main conclusions from the literature survey was that all the papers reviewed were based on past

[4] Wholesale electricity prices: the wholesale price is the price set by the wholesale electricity pool. The price generators receive for generating electricity and the price retailers pay for electricity they purchase. They can be short-term or long-term prices. Short-term prices are also referred to as spot prices.

[5] Merit Order Curve: when an electricity market is defined, the total electricity supply is usually represented by a merit order curve. Such curves range from the least expensive to the most expensive units and present the costs and capacities of all generators. Each unit is shown as a step. The differences between costs are mainly due to the technology used and its related fuel costs.

FIGURE 2: SUMMARY OF RELEVANT STUDIES AND THEIR ESTIMATED MERIT ORDER EFFECTS



data and none on future forecasts. Also, the studies focussed on single countries instead of the European power market as a whole. Therefore, there is a need for a more holistic study which encompasses several countries within the European power market. Furthermore, the various countries should be analysed under the same set of assumptions and most importantly, include a picture of the future. It would be useful to get an indication of the actual price effects in 2020 with stricter emission reduction targets and more renewables in the power mix.

Photo: Getty

3 SUMMARY OF FINDINGS

Numerous studies on merit order effects have been published in recent years. Most of them, however, are studies of single countries, e.g. Germany, Spain and Denmark. Consequently, there is a need to estimate the merit order effects at European level in order to assess total reductions in power market prices because of large-scale wind power development in Europe boosted by the EU renewable target for 2020 of a 20% renewable share of total energy use.

The report consists of the description of Pöyry's modelling analysis, which analyses and quantifies the European merit order effect; that is, the effects of increased wind power in-feed in Europe on average wholesale power prices in 2020.

The analysis is based on a comparison of two different power market scenarios for 2020. The "Reference" scenario has a constrained renewable capacity development. All renewable energy source capacity volumes, including wind, are fixed at 2008 levels. In comparison, the "Wind" scenario assumes a Europe-wide increase in installed wind capacities of 200 GW from 2008 (65 GW) until 2020, reaching a total of 265 GW. All other renewable capacities are fixed at 2008 levels as well.

A modelling tool was used to investigate the two scenarios outlining possible European power market development up to 2020. Part of the scenario analysis involves quantifying future investment needs based on the expected wind and renewable capacities. Conventional technology investments are determined by the modelling tool according to long run marginal cost levels based on the long run market equilibrium for 2020. Therefore, the study investigates the long-term price effects of increasing wind power generation. Its main assumption is that capacity is developed in an optimal way, so that all generation in 2020 is cost efficient.

Nevertheless, the report describes the long-term merit order effect of increased wind power penetration in Europe by comparing the short-run marginal cost curves for 2020 in the different scenarios (which are however in long run equilibrium). The difference in the two scenarios' equilibrium price levels for 2020 is interpreted as the merit order effect of the additional wind power generation. It is the relative difference between the average short run marginal costs which gives us the merit order effect.

The following main results were obtained by the study: The "Reference" and "Wind" scenarios result in a different equilibrium price level for 2020: the Reference scenario resulted in an equilibrium price of €85.8/MWh, while the Wind scenario indicated a price of €75/MWh.

Differences between the market equilibrium prices in the two scenarios are due to differences between the technological capacity and generation mix. Emission levels and carbon prices vary in the two scenarios. Consequently, long-run investment developments, especially for coal power technologies, are different in the two scenarios. In addition, lignite, coal and gas technologies show a higher short-term marginal cost level in the Reference scenario than in the Wind scenario due to the difference in carbon costs.

The merit order effect, the difference of the equilibrium price level between the Reference and Wind scenarios, has been estimated at €10.8/MWh in 2020.

Assuming that the entire power demand is purchased at the marginal price, the overall volume of the MOE has been estimated at €41.7 billion/year. This "volume effect" refers to the total saving to the consumers caused by the wind power penetration during a particular year.

However, decreasing income for power producers means that only the marginal part of the generation which is replaced by wind has a real economic benefit. Additionally, the economic benefits need to be contrasted with the public's support for wind power investments.

Sensitivity analysis of fuel prices that are 25% higher than those forecast by the IEA for 2020 leads to an increase in carbon prices of about €5/tonne in both scenarios[6]. This is mainly due to the indirect price relation between power and carbon prices. Higher fuel prices lead to higher marginal costs in power generation and thereby indirectly increase carbon price levels.

When fuel prices are increased by 25% in 2020, the merit order effect goes up by €1.9/MWh (17.5%) to reach €12.7/MWh. The main reason for the increased merit order effect is a higher equilibrium price in the Reference scenario. Meeting demand is, in absolute figures, more costly due to increased gas power investments which are more cost efficient than coal power technologies due to their lower carbon intensity.

The sensitivity analysis shows that higher carbon emission reduction targets yield lower merit order effects. The merit order effect in the 30% greenhouse gas reduction case is calculated at €9.4/MWh.

The sensitivity analysis shows there are higher equilibrium prices in the 30% reduction case than in the base case of 20% GHG reduction. At the same time, in the Wind scenarios, the equilibrium price levels increase more than in the Reference scenarios. The main reason for this is that at very high carbon price levels, abatements in the power sector take place by fuel switching from coal to gas. With higher GHG reduction targets, gas power investments and generation volumes increase significantly so that increased wind power has to replace gas power technologies with relative higher short run marginal costs.

The analysis applies a long term equilibrium model with a monthly time resolution. The consequence is that hourly price changes due to volatility are not shown. Greater price variations would lead to an increase in peak capacity, which would indirectly increase the cost of wind power and so decrease the short-term merit order effect.

[6] The forecast fuel prices for 2020 are €11 MWh for coal and €29 MWh for natural gas. These are taken from IEA World Energy Outlook 2009 – in combination with assumptions of the New Energy Policy scenario found in: "An EU Energy Security and Solidarity Action Plan – Europe's current and future energy position demand – resources – investments" {COM(2008) 781 final}. More information can be found in the annex to this chapter.

Photo: iStock

4 METHODOLOGY

This chapter describes how the merit order effect of increased wind power feed-in in the European power systems is quantified. A modelling tool is used to assess the average power price levels for different future scenarios, based on different amounts of wind power. The scenarios are described in detail on page 142. The modelling tool and its application are introduced briefly on page 138.

4.1 Approach

The merit order effect of wind power in Europe is analysed by looking at two scenarios which present different market developments in terms of wind power feed-in in 2020. A Reference scenario: renewables have the same share of power supply in 2020 as in 2008. There are no further investments in wind or other renewables.

A Wind scenario: the power generation mix focuses on wind power. Wind capacity goes up 300% from 65 GW in 2008 to 265 GW in 2020.

Pöyry integrates the scenarios into its model-based analysis, defining the remaining assumption parameters and input data in order to calculate the wholesale market price levels in 2020 for both scenarios. The merit order effect was estimated to be the difference between the market prices in the two scenarios considered. All the average prices presented reflect long-run marginal costs for 2020. Future investments are included in the modelling analysis by simulating the optimal economic development of capacities additional to the assumed wind capacities. Further details on the modelling methodology follow on page 142.

Scenario development

The scenarios were developed so that the modelling analysis could show the effect of the additional wind capacities on the future power system. For this reason, the main difference between both scenarios is the amount of wind capacity. In the reference scenario, wind capacities are kept at the 2008 level and no additional increase in wind capacities is assumed. In contrast, the Wind scenario has wind power capacity increase from 2008 to 2020 following EWEA's "High" scenario for 2020.[7] For the sake of the simulation, all other renewable sources and their capacities have been kept constant at 2008 levels in both scenarios, so that they present the same relative shares of total electricity demand in 2020 as in 2008.

In the development of the two scenarios which will form the basis for the modelling analysis, major market variables used as model input, such as fossil fuel prices, power demand, carbon reduction targets and conventional investment costs and have been determined for each scenario. Each scenario has only been developed for 2020, so that the overall analysis consists of two models. The results from this modelling analysis include the average annual wholesale price levels for electricity per country and the merit order curve for all countries covered by the analyses (EU 27 plus Norway and Switzerland). Moreover, power demand, generation, the technology mix, transmission, investments and the carbon price could be shown for each scenario and the year respectively.

In Table 1 below, the scenario assumptions on the main input parameters for both scenarios are summarised and compared. The red marked cell demonstrates the only difference in the input scenario assumptions between the two scenarios.

The figure below indicates the assumed wind capacities for both scenarios. The Reference scenario represents 2008 values. The installed capacities given for the Wind scenario represent the high values from EWEA's Pure Power scenarios. The figure also indicates the separate countries by its darker blue marking.

FIGURE 3: ASSUMED WIND CAPACITIES OF THE REFERENCE AND WIND SCENARIO

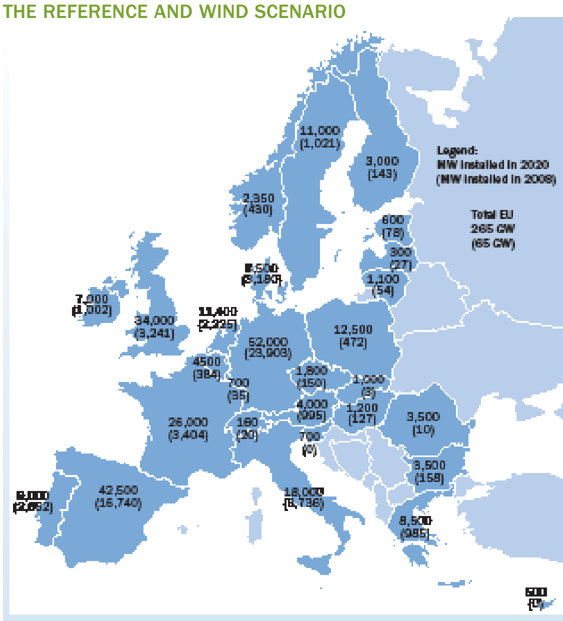


TABLE 1: SCENARIO ASSUMPTIONS

Input parameter	Reference scenario	Wind scenario
Fuel prices	Forecast from IEA	Forecast from IEA
	Coal: €11/MWh, Gas: €29/MWh	
Wind capacities	As 2008	High growth compared to 2008
Carbon policies/targets	EU target: -20% to 1990	EU target: -20% to 1990
	CO_2 price: €48/tonne	CO_2 price: €30/tonne
Conventional investments	According to long run marginal costs	According to long run marginal costs
Capacities of RES other than wind	As 2008	As base year 2008

Colour code: For the same "Input Parameter", blue marked cells represent the same value. Red marked cells are representing a different input value compared to the other scenario. The green marked cells are calculated model output and mentioned for the sake of completeness.

[7] Pure Power- Wind energy targets for 2020 and 2030, A report by the European Wind Energy Association - 2009 update.

4.2 Modelling

Modelling tool

In order to carry out the modelling analysis, Pöyry applied its modelling tool "The Classic Carbon Model" (see Annex). It includes a fully fledged model of the European power market. The Classic Carbon model is an advanced simulation tool for analysing interaction between the power and carbon market. It is a general equilibrium model that assumes perfectly competitive markets. It is a combination of a bottom-up and top-down model, capturing the fundamental supply and demand functions in the power and carbon market. In mathematical terms, the model maximises total welfare with a number of basic constraints. Such constraints are, for example, that power demand has to equal supply at all times, and then there are transmission constraints, CHP generation profiles, CO_2 emission reduction targets and so on. According to economic theory, the outcome from welfare maximisation is equivalent to the outcome in a perfectly competitive market in which producers maximise profits and consumers maximise utility.[8] Although it is based on the assumption of perfectly competitive markets, Classic Carbon is also able to capture the effects of market power by adjusting data parameters for market power.

The Classic Carbon model and hence the modelling analysis cover the European power and carbon market – that is, the EU-27 countries plus Norway and Switzerland.

Concerning the carbon market, the model finds equilibrium between supply and demand of allowances in the EU Emissions Trading System (ETS) market for the whole trading period and equilibrium between supply and demand of power in each country simultaneously. In the model, emissions from power generation, heat generation and production in ETS industries are "matched" with the cap. That is, the total emissions from these sectors must be lower than or equal to the total amount of allowances. The model also allows for imports of non-European credits from the Kyoto-based project mechanisms. Imports are restricted by a volume cap in accordance with EU regulations, and are estimated externally in regard to price differences compared with EUA price levels.

The Classic Carbon model is designed to model long-run market fundamentals, and captures the impact of power demand developments, interconnector capacities, fuel developments, energy policies, emission levels and so on.

In addition to the power market, the model includes the heating sector and the industrial ETS sectors. It simultaneously finds a balance between supply and demand in the power market and a balance in the EU ETS market. Model results include wholesale and end-user prices for each market area, trade flows, generation, demand, fuel use, CO_2 emissions and the carbon (EUA) price. A more detailed description of the model can be found in the Annex.

Modelling approach

In the following modelling analysis, Pöyry applied its Classic Carbon model to estimate the long-term effects of power capacities in 2020 on the merit order curve through increased wind power capacities which change the use and profitability in traditional base load capacity. Hence, the Classic Carbon model simulated how long-term market equilibrium may be affected by the impact of large-scale wind investments on conventional power technology investments (based on short-run marginal costs and fixed investment costs). These impacts have been indicated by the model through the average market price levels in 2020 at a national level (for all EU-27 countries) as well as at a European level. The relative price differences between the two scenarios indicated the merit order effect of increased wind power in electricity production.

[8] Compare, for example, Varian (1992), Microeconomic Analysis, third edition, Norton, New York. This is one of the main arguments for competitive markets.

In addition to power prices, the Classic Carbon model also calculated the trade flows and investments needed to meet the predicted levels of demand. Investments are calculated based on short-run marginal costs and fixed investment costs. For the model runs we added figures for investments in renewables and let the model fill in the remaining gap between demand and capacity.

Since the analysis was estimating prices for 2020, the modelling tool was used to simulate the capacity investments required in addition to the renewable capacities put into the model. The remaining capacities were simulated in accordance with the long-term economic feasibility of an investment - its long-term marginal costs. The market price had to guarantee that all investments were cost efficient in the long term in order to reach market equilibrium.

The starting year for simulations up to 2020 is 2008. The capacities, costs, generation and demand levels of 2008 are given as input data. The scenario data for 2020 is defined and put into the model. This includes wind capacities, future investment costs, fuel prices, emission caps and demand levels. The model optimises supply and demand for 2020. If required it finds additional investments, but only if the long-run marginal costs can be covered by the prices seen on the market. Hence, if the potential income from the sale of the power is higher than the annual income requirement of the project (including 8% rate of return) during 2020, investment would take place.

Since investments are based on price expectations, and the prices calculated for 2020 guarantee that generation is cost efficient in that year, it can be assumed that short-term prices in 2020 also ensure cost efficiency in that year in order to reach market equilibrium. So wind power capacities with very low short-run marginal costs push the cost inefficient capacities out of the merit order curve so they do not produce any more. Consequently, the average price levels are reduced, which is of benefit to the consumers, but which also reduces the incentive to invest in new production capacity.

In the modelling analysis, the difference in the two scenarios' average price levels for 2020 is interpreted as the merit order effect of the additional wind power generation. It is the difference between the average prices which gives the merit order effect.

The Classic Carbon model runs on a time resolution with two levels. The simulation year, 2020, is divided into 12 time periods, each representing one month. Each time period is then divided up into up to -five load blocks. The load blocks represent the varying load levels experienced in each period and generally correspond to times of the day, such as night, weekend, day, evening, day-time peak, and so on. The model's optimisation then takes place for each defined load block.

For this reason, the calculated merit order price effect generally only concerns the monthly average prices. Daily effects, such as the shape of the hourly price curve, are not analysed and indicated.

Because of its variability, a large amount of wind power would have a significant effect on a thermal system by increasing the number of hours where zero or very low electricity prices appear. Price structures would indicate a higher volatility. The reason for this is that when the wind blows, wind power will be fed into the system and merit order curve first, with its very low marginal production and opportunity costs (wind power's capital costs are not included in this calculation) The "opportunity costs" are the implicit costs of wind power on the environment and society. If wind power capacities produce at almost zero opportunity costs whenever the wind blows, the market price drops in low load hours when there is other base-load generation that is not running cost efficiently (for example CHP or nuclear that is running over night). This effect on the prices is most significant in the regions where most wind power capacity is installed. However, these effects are not included in this modelling analysis.

Any short-term price effects basically referring to the price volatility were not covered and described by this project and this report.

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5 ANALYSIS

5.1 Modelling results

Merit order curve

When describing the power market, the total electricity supply is usually represented by a merit order curve. This ranges from the least expensive to the most expensive generation units, in which each cluster of power production technologies is shown as a step. The merit order curve presents the marginal costs and capacities and/or generation of all market's generators in a certain time period.

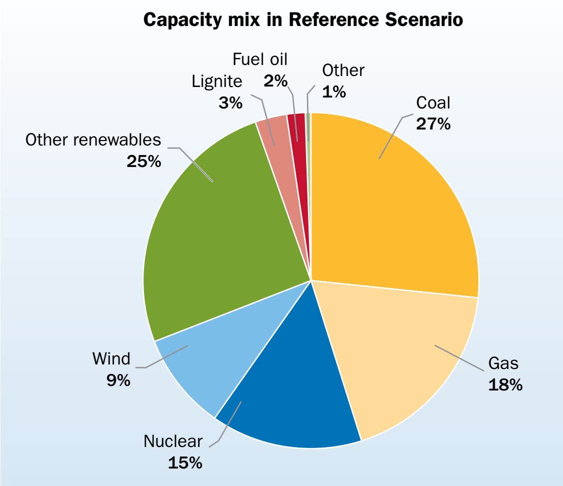
The merit order curve for the European power market based on the Reference scenario is shown in Figure 5[9]. In this scenario, wind capacities in 2020 are kept at the same level as the actual figures from 2008. Hence, the Reference scenario results indicate there will be about 160 TWh of wind power in 2020, meeting 4.1 % of total power demand.

The respective overall capacity mix for the Reference scenario can be seen in Figure 4. The total installed capacity in the year 2020 is about 806 GW.

The merit order curve below shows all of the Reference scenario's generating technologies in the European power market in 2020 and each one's generation volume sorted according to its short-term marginal costs. The x-axis of the graph represents the power generation volume of different technologies in 2020. On the y-axis, the technologies' corresponding marginal costs

[9] The Carbon Classic Model includes the EU 27 countries plus Norway and Switzerland. However, following countries are summarised as "external regions": Malta, Cyprus, Ireland, Luxembourg, Bulgaria and Romania. Detailed results for these countries are not available and therefore they are not represented in the merit order curves and MOE.

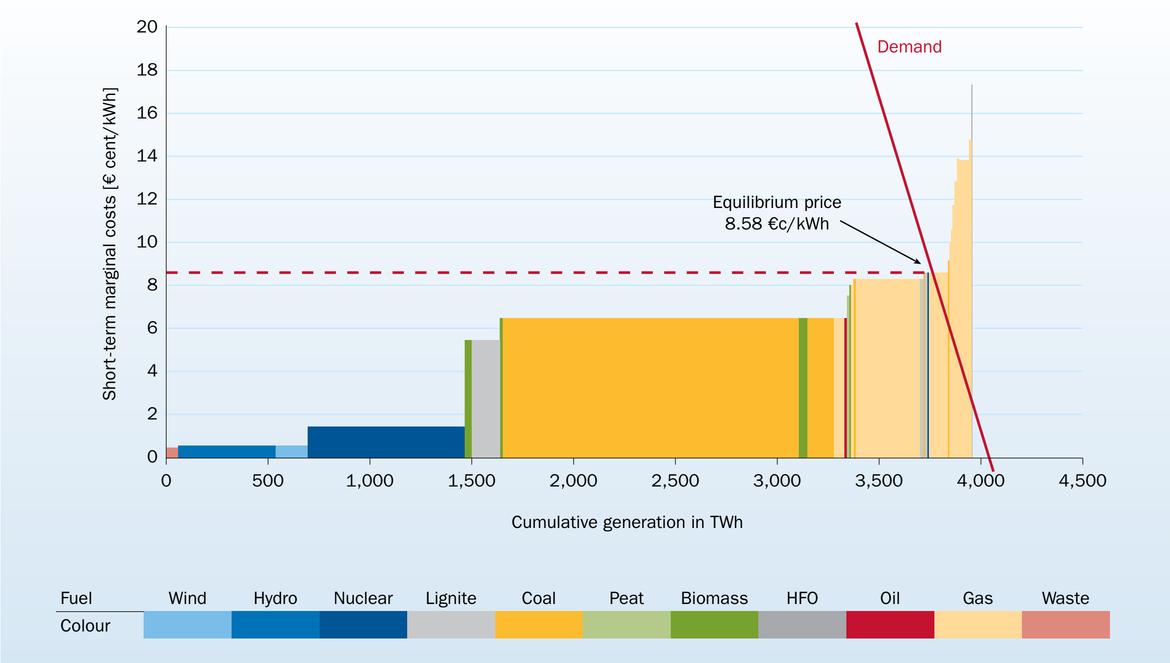
FIGURE 4: MODELLED CAPACITY MIX OF THE REFERENCE SCENARIO IN 2020



are depicted. The technologies are sorted according to their short run marginal costs and the type of fuel they use. Although the graph indicates the short-run marginal costs, it is based on the long-term market equilibrium, which assumes the cost efficiency of all generating units. However, in order to follow the customary way a merit order curve is depicted, and make it comparable, the curve below only includes non-fuel variable costs, transport, fuel and carbon costs but no capital costs (see the Annex for a more detailed description of the model's cost assumptions). The power market's equilibrium price, when the total demand is 3,754 TWh, has been estimated at 8.58 €cents/kWh.

From the merit order curve, it can be seen that European power demand is first supplied by waste, hydro and wind technologies as they have the lowest short-term marginal costs. These technologies provide about 680 TWh altogether, with hydro providing two-thirds of this. Conventional existing nuclear technologies provide 780 TWh at marginal costs of 1.5 €cent/kWh on average.[10] The major share of Europe's demand, about 1,700 TWh, costs between 5 and 7 €cent/kWh. It is made up mainly of hard coal technologies and a very small share comes from lignite and biomass technologies. At higher cost levels, gas technologies dominate, supplying about 500 TWh per annum. The Reference scenario's marginal technology at the equilibrium price is combined cycle gas turbines.

FIGURE 5: MERIT ORDER CURVE OF THE REFERENCE SCENARIO FOR 2020



[10] Non fuel variable costs are estimated at €~10/MWh for new nuclear plants. Older plants might have slightly higher variable costs. Fuel costs are assumed at € 1.2 – 1.5/MWh fuel. At efficiencies of 35-37% this means fuel costs of € 3.5 - 4/MWh. Sources are presentations from the EDF 2009 Energy UK Suppliers Forum – New Nuclear Opportunities and publications of Swedish nuclear plant operators.

In order to assess the merit order effect of additional wind power capacities, the merit order curve of an additional Wind scenario (described on page 140) has been analysed and compared to the Reference scenario.

In the Wind scenario, an additional 200 GW of installed wind capacity (making a total of 265 GW) has been introduced for 2020. All other exogenous renewable and conventional capacity inputs to the model were the same as in the Reference scenario. In addition, the model realised that there would be insufficient capacity to meet supply. Hence, the two scenarios vary in their endogenously modelled conventional capacity development.

In the Wind scenario, the total installed capacity in 2020 was modelled at 960 GW. Its capacity mix can be seen in Figure 6 below.

Figure 7 shows the Wind scenario's merit order curve. It can be seen that wind technologies generate about 650 TWh compared to 160 TWh in the Reference scenario. Wind power technologies therefore displace more expensive generating technologies in the merit order curve and shift them to the right in the figure below. As a result, the scenario's total demand level of 3,860 TWh can be supplied at a marginal cost and equilibrium price level of 7.5 €cents/kWh.

FIGURE 6: MODELLED CAPACITY MIX OF THE WIND SCENARIO IN 2020

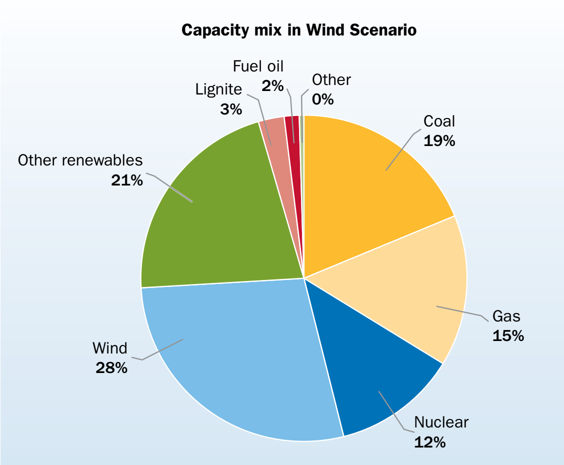
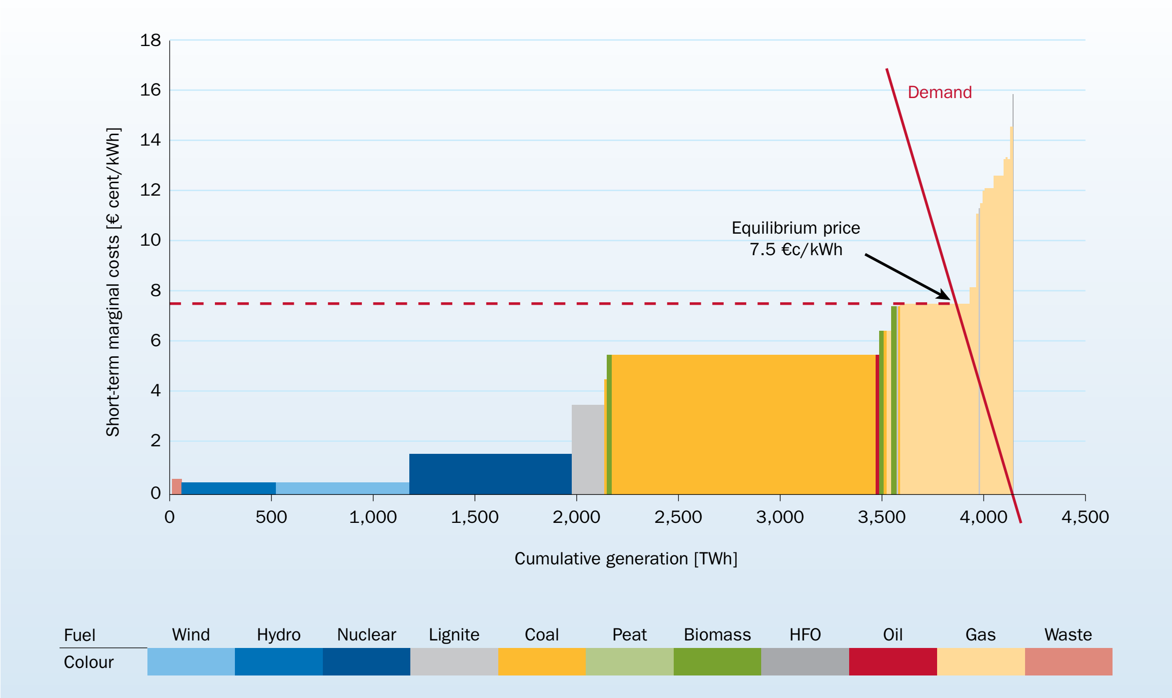


FIGURE 7: MERIT ORDER CURVE OF THE WIND SCENARIO FOR 2020



The technology mix and sequence of the Wind scenario's merit order curve very much resembles that of the Reference scenario. The main difference is the greater wind power generation, which shifts all the more expensive generation technologies to a higher cumulative generation volume (to the right in the curve). This means the generation volume of nuclear technologies and lignite stays constant in both scenarios. The volumes of coal, gas and non-wind renewable generation volumes are lower in the Wind scenario than in the Reference scenario. The detailed generation volumes are illustrated and compared in Table 2. It can be concluded that in the Wind scenario, wind power mainly replaces generation from coal and gas technologies, which are replaced because they have the highest short-term marginal costs. However, in the Wind scenario as in the Reference scenario, the marginal technology type at the equilibrium price of 7.5 €cent/kWh are combined cycle gas turbines.

Both scenarios show the market in equilibrium. According to the methodology, in addition to the wind capacities, the modelling tool finds capacities needed to meet demand in order to reach equilibrium. Here lies the main difference between the two scenarios. The Reference scenario contains a significantly higher investment volume in conventional capacities than the Wind scenario. Coal capacity investments are about 30,000 MW higher and natural gas technology investments are about 5,000 MW higher than in the Wind scenario. The main reason for the price differences in the two scenarios is the difference in long-term marginal costs due to the differing investments.

In the merit order curves above, the cost differences are mainly due to the technology used and are related to the type of fuel. For instance in both the scenarios, nuclear and coal power plants have lower marginal costs than most of the gas powered plants.[11] This is due to the lower fuel costs for coal and nuclear.

It can be seen that the results are very sensitive to fuel price assumptions and the assumed relative difference between the coal and gas prices. In order to estimate the impact of the fuel price assumptions and its uncertainty, a sensitivity analysis has been made and is described in a later chapter of this report.

Furthermore, the short-term marginal cost levels for the conventional technologies also vary in the two scenarios because of the resulting difference in the CO_2 price. One impact of increased wind power generation will be reduced demand from the power sector for emission allowances under the EU ETS through lower baseline emissions. This means the residual demand for abatements from the industry sector and additional fuel switching in power and heat production is reduced. As a result, carbon price levels also go down and consequently, the Wind scenario results in a carbon price level of €30/tonne of CO_2 in 2020 compared to €48/tonne in the Reference scenario.

Therefore, lignite, coal and gas technologies show a higher short-term marginal cost level in the Reference scenario than in the Wind scenario due to the difference in carbon costs.

TABLE 2: GENERATION VOLUMES IN THE YEAR 2020 PER TECHNOLOGY

in TWh	Nuclear	Lignite	Coal	Wind	Non-wind renewables	Natural gas	Others
Reference Scenario	800	165	1,638	161	611	563	27
Wind Scenario	800	165	1,373	648	603	457	26

[11] This refers to the plants' short run marginal costs which include fuel costs, carbon costs and non fuel variable operation costs. In a long run marginal cost consideration, also including capital costs for the overnight investment coal technologies usually show higher cost levels than gas technologies.

Merit order and volume merit order effect

As shown in the previous chapter, due to wind's lower marginal costs (zero fuel costs), when there is more of it on the power system, it replaces conventional technologies and the price goes down. Consequently, some of the most expensive conventional power plants might be no longer needed to meet demand. At a fixed demand level, as long as the whole merit order curve has a positive slope, the reduced conventional supply leads to a lower average power price. As this means market prices are shifted along the merit-order of the market's power technologies, the effect is called merit order effect (MOE).

In this study, the merit order effect is determined by calculating the difference in the long-term equilibrium price level of the Reference scenario and the Wind scenario.

In the analysis, the merit order effect – the difference between the equilibrium price levels in the two scenarios – has been estimated at 1.08 €cent/kWh or €10.8/MWh. The Reference scenario resulted in an equilibrium price of 8.58 €cent/kWh whereas the Wind scenario indicated a price of 7.5 €cent/kWh.

Assuming that the entire power demand is purchased at the marginal price, the overall volume of the MOE can be calculated for the scenarios. The "volume effect" refers to the total savings made due to wind power penetration in a particular year. The price difference of the two scenarios would represent the volume merit order effect of increased wind power capacities. It could be calculated by taking the equilibrium price difference of both scenarios, 1.08 €cent/kWh, multiplied by the Wind scenario's overall demand of 3,860 TWh.

The overall volume merit order effect, comparing the Wind scenario price with the Reference scenario price would then be €41.7 billion per year[12].

However, it would be misleading to interpret this as the overall economic benefit of increased wind power generation. When wind power reduces the average power price, it has a significant influence on the price of power for consumers. When the price is lowered, this is beneficial to all power consumers, since the reduction in price applies to all electricity traded – not only to electricity generated by wind power. However, at the same time, the power producers' short-term income decreases at lower power prices, meaning the MOE causes a redistribution of income from the producers to the consumers of electricity. Only the long-term marginal part of the generation which is replaced by wind has a real economic benefit.

However, the assumed amount of additional wind power investments has an economic cost, usually given through investment subsidies, feed-in tariffs or other support. For this reason, in order to determine the actual economic benefit of increased wind power generation, the annual savings in costs deriving from the merit order effect should be related to the total annual costs in form of wind power support.

There is only an overall economic benefit if the volume of the merit order effect exceeds the net support for wind power generation, paid for by the end-consumer. Ideally, subsidies to fossil fuel and nuclear power should also be taken into account to determine the economic benefits, but this is beyond the scope of this analysis.

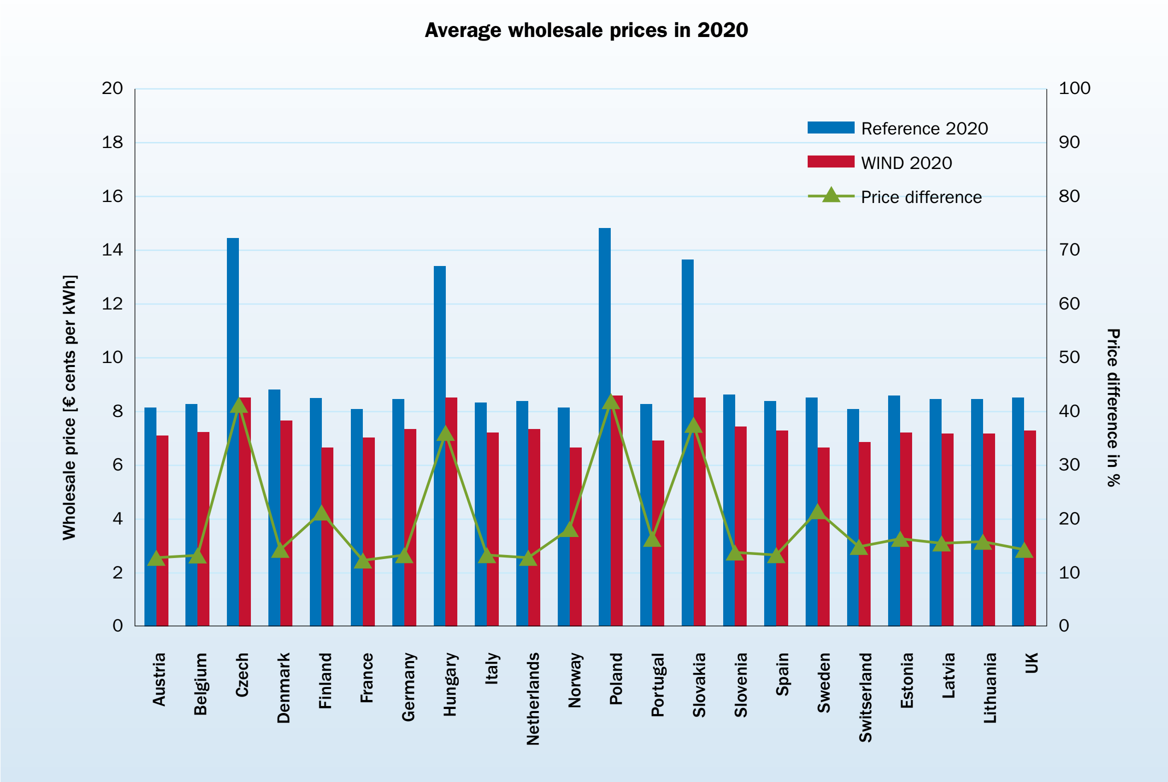
TABLE 3: OVERVIEW ON MODELLING RESULTS: MERIT ORDER AND VOLUME MERIT ORDER EFFECT.

	Wind generation volume	Merit order effect	Volume order effect	Merit order effect per wind MWh
Year	TWh/a	€/MWh	billion €/a	€/MWh
2020	648	10.8	41.7	64.4*

**This figure indicates the merit order effect for 1 MWh of wind power. It is calculated by dividing the volume order effect by the total wind generation volume. It should be compared to the support level given to wind power generation per MWh, in order to estimate the economic benefits of wind power.*

[12] In the project's first phase, the conducted literature survey indicated some volume order effects, only for single countries, e.g. Germany. There, a volume order effect of €1.3 - 5 billion per annum has been shown. In comparison, this model analysis would result at a volume order effect of €6.7 billion per annum for Germany, if looking at the country specific results only.

FIGURE 8: AVERAGE WHOLESALE PRICES PER COUNTRY FOR2020



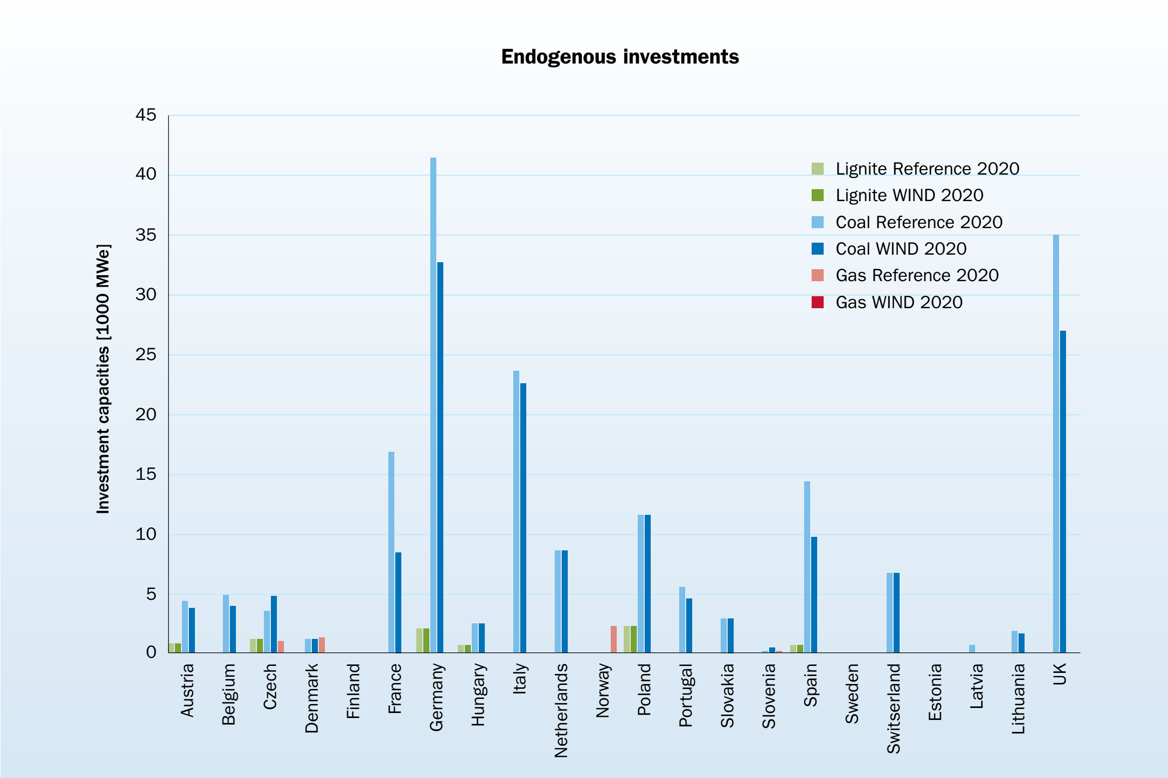
Wholesale prices

In both scenarios and in most countries, input data assumptions are made so that the amount of new deployment of wind energy is larger than the increase in power demand, and that wind energy will replace the most expensive power plants. This will lower the average price levels.

In the EU the expected price level for 2020 is around 8.9 €cent/kWh for the Reference Scenario (Figure 8), with a significant higher price in the Czech Republic, Poland, Hungary and Slovakia. In the latter countries, the average price is about 50% higher than the EU average. The main reason for their high average price levels are that these countries base their generation very much on coal power, which means there are relatively high carbon costs. In these countries, some old power plants are very inefficient and therefore emit significantly more carbon. In addition, for the Czech Republic and Poland, power demand in the Reference scenario exceeds the country's power capacity. Highly expensive technologies therefore have to produce power in order to cover demand. These two countries are net importers of electricity, mainly from Germany and Slovakia. As a consequence of its large amounts of exports to Poland, the Czech Republic and Hungary, Slovakia has also become a high price region. And Hungary also lacks its own generation capacities, so it imports from high price regions like the Czech Republic and Slovakia (see more details on page 150, Trade flows).

In the Wind scenario, average prices are about 18% lower than in the Reference scenario. The EU average price is around 7.3 €cent/kWh in the Wind scenario. Again, the Czech Republic, Poland, Hungary and Slovakia have higher prices than the EU average, but only around 15% higher, which is a smaller price difference than in the Reference scenario.

FIGURE 9: ENDOGENOUS INVESTMENTS FOR DIFFERENT SCENARIOS UNTIL 2020



Different effects can be seen in the hydropower-dominated countries Sweden, Finland and Norway to those seen in the thermal-based countries on the European continent.

In addition to the extreme price differences for Poland, Czech Republic, Hungary and Slovakia, as described above, Figure 8 also indicates that wind energy lowers the price more in some hydro-based countries, namely Finland, Sweden, Norway and Portugal. Here, a large-scale implementation of wind power means there is a greater need for flexible production within the country rather than for exporting hydro power to deliver balancing services in neighbouring countries. This means trade flows from these countries to neighbours are decreased in the Wind scenario (see Figure 13).

Consequently, large-scale wind implementation increases the incentive to invest in more grid capacity i.e. in more interconnection capacity between different price areas.

Other results

Investments

Large wind power investments supersede the additional investments in conventional power plants that would otherwise be needed in order to match power supply and demand. The types of technologies that are replaced depend on the investments that would have been made without the large-scale deployment of wind power.

Due to an increase in power demand and plans to decommission some nuclear power plants and old conventional plants additional investments in conventional power are expected to be needed.

FIGURE 10: TOTAL ELECTRICITY DEMAND ASSUMED IN THE MODELLING ANALYSIS

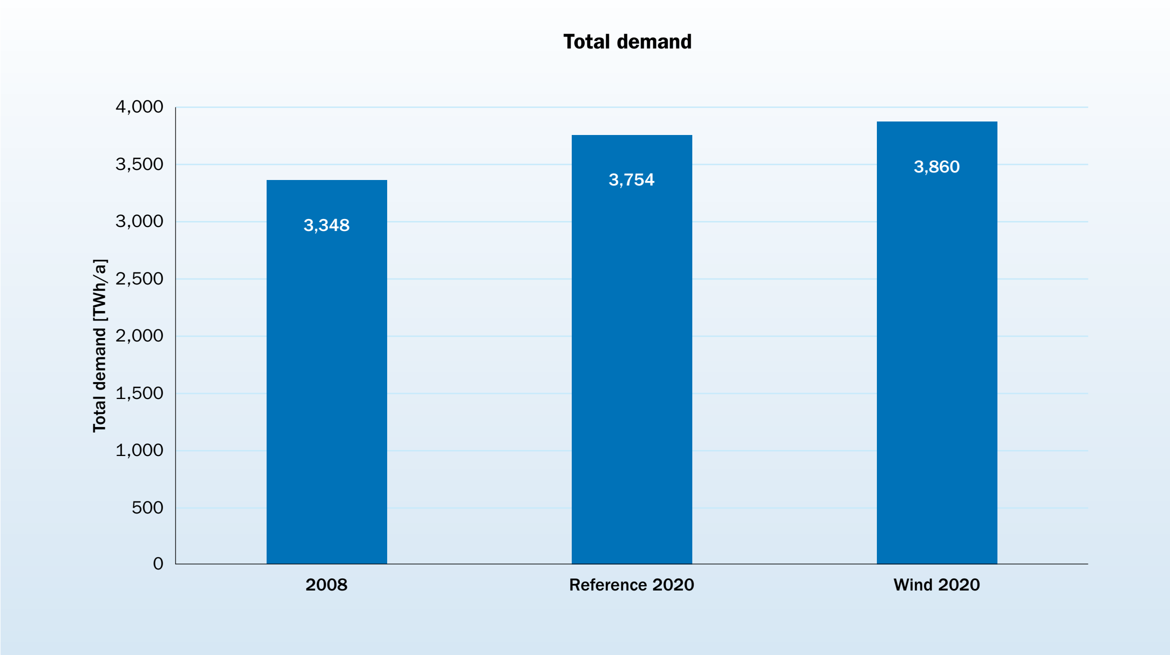


Figure 9 depicts the investments the Classic Carbon model is simulating in order to meet the scenarios' power demand. Investments are made in accordance with long-term marginal costs. In a perfect market, the model will invest in the least expensive technology as long as the expected power price exceeds the long-term marginal costs.

It can be seen above that endogenous investments only take place for conventional lignite, coal and gas technologies[13]. For both scenarios, most of the future investments will be in coal. For most of the countries, the Reference scenario requires more investment than the Wind scenario. This is because with power demand increasing from 2008 to 2020 by more than 400 TWh/a (see Figure 10), the older capacities are phased out and additional new capacities are needed in order to meet demand. The Wind scenario reduces the need for conventional investments. (For the model's detailed long run marginal cost assumptions, see Annex 1).

However, in most countries, wind investments alone are not sufficient to cover demand, and additional conventional investments take place. Usually, investment in conventional power generation technologies are higher in the Reference than in the Wind scenario, except for in the Czech Republic and Slovenia. Here, obviously, the extremely high investments in wind power in the Wind scenario require additional base-load capacity investments. Consequently, investment in coal is higher in the Wind than in the Reference scenario for these countries.

The investment developments described above include peak capacity developments. The Classic Carbon model includes volatile generation profiles for different technologies, for example for wind power. For each period over the year a statistical wind profile is used to simulate wind power generation. As a consequence, the model might also invest in peak capacities, mainly gas turbines, in order to supply peak demand if necessary.

[13] "Endogenous" investments mean investments which are a model result. They are simulated by the model in order to balance supply with demand. In comparison, the model also includes "policy based" investments which are forced into the model as input assumption, e.g. known shut downs and known investment projects already under construction.

FIGURE 11: TOTAL INSTALLED CAPACITIES IN EUROPE, 2008 AND 2020

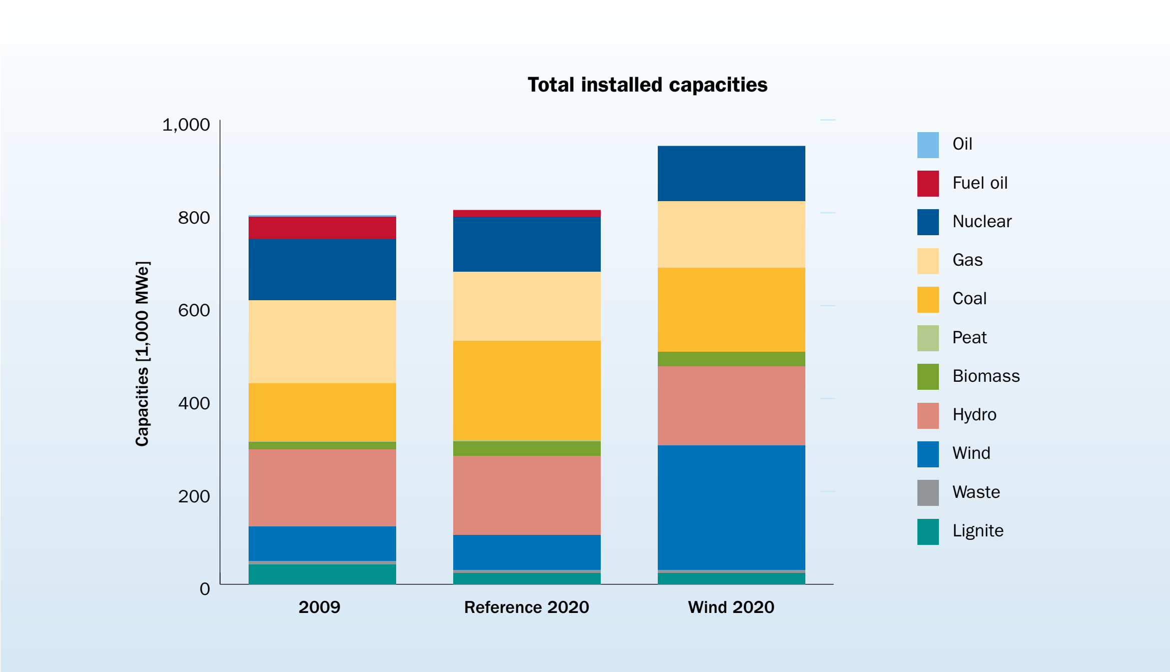


FIGURE 12: GENERATION VOLUMES IN TWH/A, 2008 AND 2020

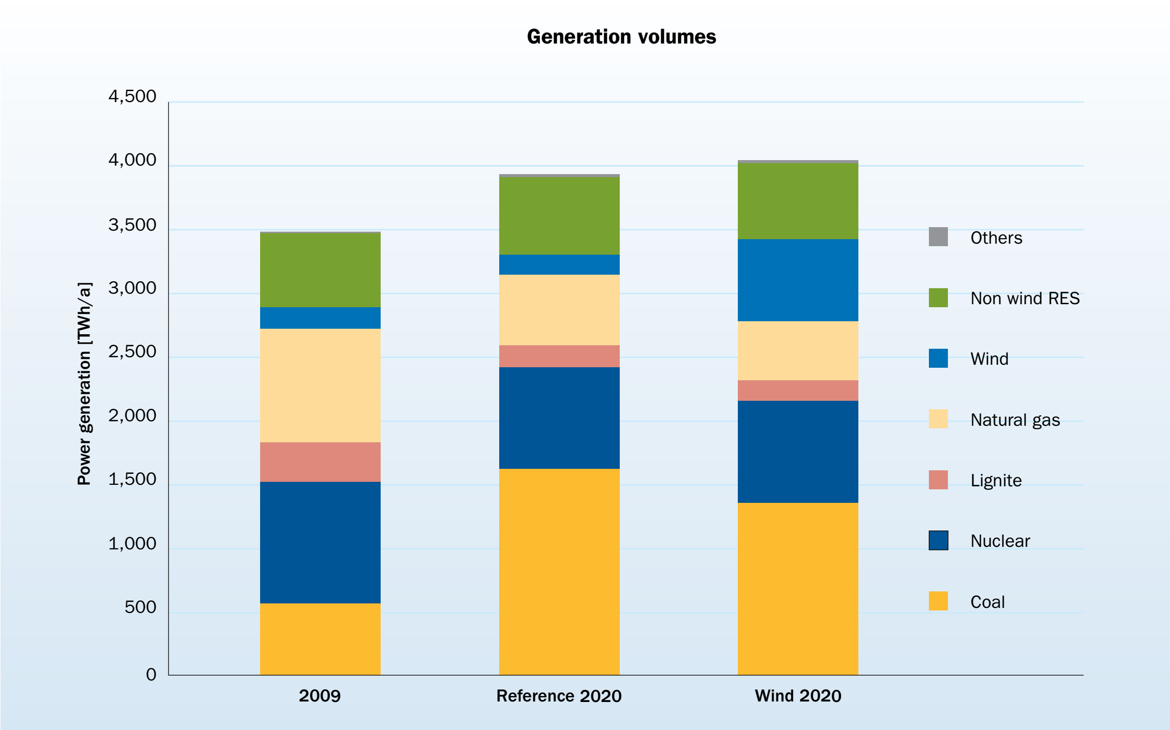
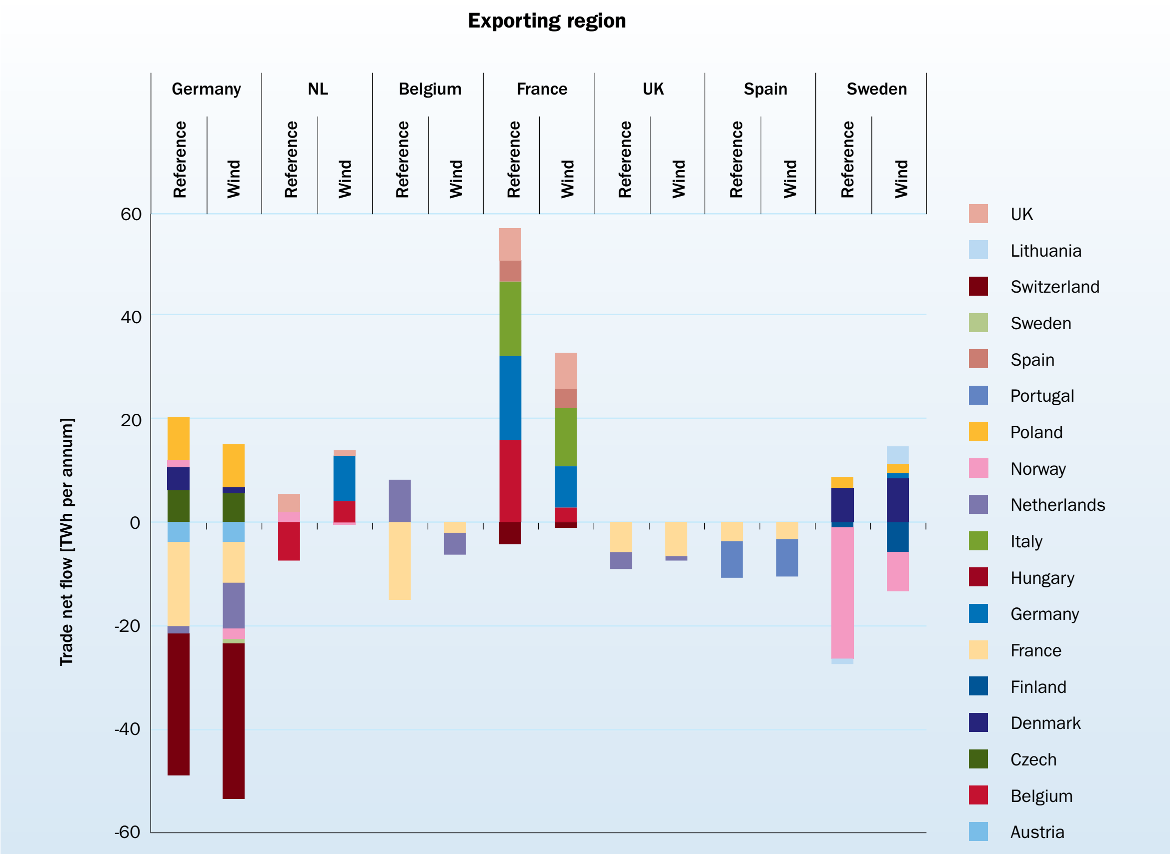


FIGURE 13: TRADE FLOWS OF BOTH SCENARIOS FOR THE CHOSEN COUNTRIES IN 2020



From the exporting region's point of view, positive figures present net exports, negative figures present net imports.

Total capacities

The total installed capacities in the two scenarios can be seen below in Figure 11. The Reference scenario gives a total installed capacity of 775,000 MW in 2020, with a total demand of 3754 TWh/year. In comparison, the Wind scenario shows a slightly higher demand, 3,859 TWh/year, and a significantly higher total capacity with 908,000 MW[14]. As already described on page 149, in the Wind scenario, 200,000 MW additional wind capacities (total 265 GW) have been added to the model. And as a consequence, conventional capacities whose total volumes are therefore lower in the Wind scenario than in the Reference scenario are replaced, especially coal and gas technologies. The detailed mix of the total installed capacities for both scenarios can be seen in Figure 11.

TABLE 4: ASSUMPTIONS ON RENEWABLE ENERGY SHARE OF FINAL ELECTRICITY DEMAND.

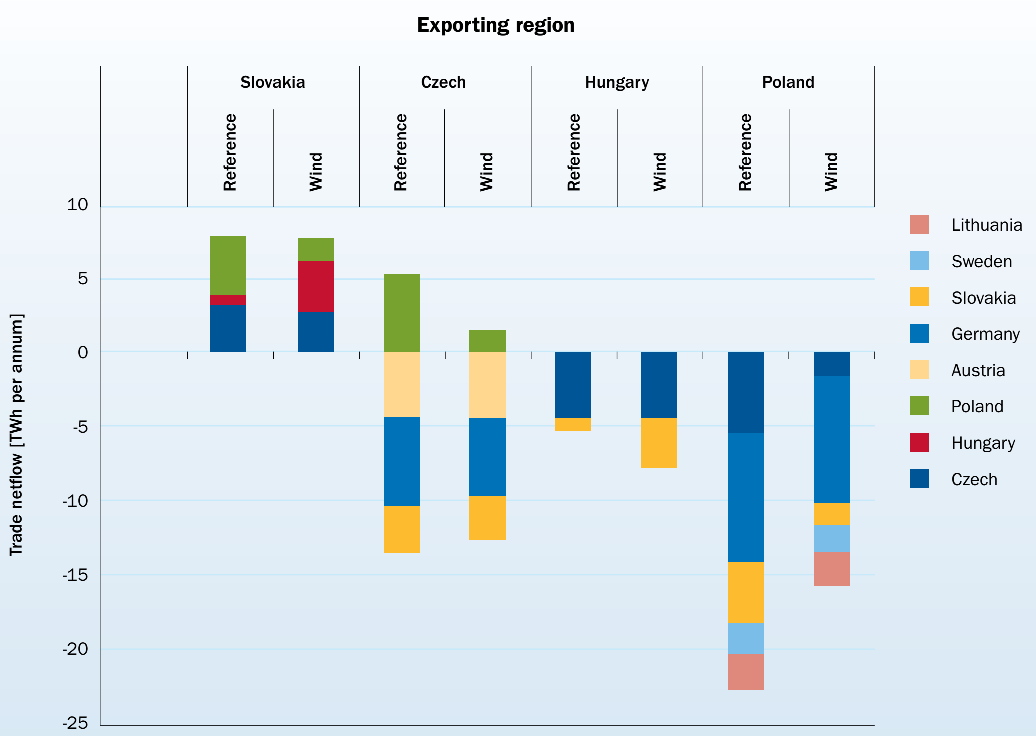
2008	Reference 2020	Wind 2020
22 %	22 %	32 %

Generation volumes

The electricity generation mix of the two scenarios can be seen in Figure 11. For modelling purposes, the scenario assumptions have been chosen so that the overall EU renewable electricity target for 2020 (34% of

[14] Differences in the scenarios' total demand level are due to price elasticities included in the model.

FIGURE 14: TRADE FLOWS FOR CHOSEN EASTERN EUROPEAN COUNTRIES IN 2020



From the exporting region's point of view, positive figures represent net exports, negative figures represent net imports.

final electricity consumption from renewable sources) is not reached in either scenario. The Reference scenario results in a renewable share of 22% of final electricity consumption in 2020, compared to a share of 32% in the Wind scenario.

In Figure 12 below, the simulated generation volumes for the different scenarios are illustrated.

Trade flows

In the Classic Carbon model, cross border transmission is modelled from an economic standpoint, with each connection from any one region to any other region having a specified (linear) loss, cost, availability, and capacity.[15] So, normally transmission is price-based, i.e. based on price differences (the price includes losses and transmission fees). But, in some cases, the transmission is fixed between regions, based on contracts between the regions (for example Finland and Russia).

In general, larger amounts of wind power in the system, lead to an increased need for interconnection capacity.

This is confirmed by the results from the Classic Carbon model: when significant investments are made in wind, the congestion rent (i.e. the cable income) increases on most transmission lines. This is also something one would expect: with more volatility in the system, there is a need for further interconnection in order to be better able to balance the system. In the model's assumptions, total EU transmission capacities have been increased from today to 2020 by about

[15] Within a given country, the model assumes there are no transmission bottlenecks. Internal transmission and distribution losses, however, are accounted for by using linear loss functions, with user specified parameters. A loss function represents the loss (cost in money or loss in utility) associated with an estimate being "wrong" (different from the given capacity as a true value) as a function of a measure of the degree of wrongness (generally the difference between the estimated value and the true or desired value.)

20,000 MW. The costs of transmission expansion are not included in the calculations and the results above.

However, mapping net trade flows gives a very disparate picture, with some countries increasing their net trade flows enormously and others decreasing them depending on the specific power capacity being developed in each country. The following two graphs indicate the main countries' net trade flows for both scenarios. Positive trade flows indicate a net export from the countries listed in the top line to the country named in list to the right of the graph. Accordingly, negative figures indicate net importing trade flows for the country listed in the top line. Nevertheless, the graph does not give a full picture of the hourly utilisation and congestion of transmission capacities.

5.2 Sensitivities

Needless to say, there is a significant degree of uncertainty linked to the results presented above. In this section, we present and discuss a sensitivity analysis of some of the major driving factors that influence the merit order effect of fuel prices and the overall GHG reduction targets.

In detail, the following sensitivities have been investigated:
1) Fossil fuel price increase by 25%
2) 30% European greenhouse gas emission reduction target in 2020 compared to 1990 levels

In comparison, the results presented previously have been based on the assumption of Europe meeting its target of a 20% reduction in greenhouse gas emissions by 2020 compared to 1990 levels.

Varying market situations such as supply and demand imbalances can affect fuel prices in the short term. In the longer term, the cost of production has a very significant impact on the average fuel prices, but local market conditions, which include the forces of supply, demand, competition, policies and government regulation, can also have a significant impact on future fuel prices, and explain the uncertainty involved in forecasting fuel prices. In order to reflect the uncertainty in this study's long-term fuel price forecast, a sensitivity analysis was carried out.

Moreover, since the UN Climate Conference (COP 15) in Copenhagen in December 2009, the European Commission has been stressing that it is of the utmost importance that the EU maintain its global lead as the world shifts towards a low-carbon economy. The EU has said it will move to a 30% reduction in greenhouse gases by 2020 compared to 1990 levels if other developed countries commit themselves to comparable emission reductions and developing countries contribute adequately according to their responsibilities and respective capabilities. But although COP 15 did not result in a global agreement on a future greenhouse gas emission reduction target, and the outcome left a lot of political and market related uncertainty, the EU Commission has been analysing the possibilities for the EU to move from its current 20% reduction target to the 30% GHG reduction target nonetheless.[16] So, there is a chance that the assumed greenhouse gas emission target for the EU ETS sectors within this study will become even higher. The following sensitivity analysis therefore looks at how this more ambitious GHG reduction target would influence the results of the study on MOE.

Fuel prices

The merit order effect is indicated with the help of the short-run marginal cost curve for 2020. In general, short-run marginal costs include non-fuel variable costs, fuel and transportation costs as well as carbon costs. Fuel costs have a major influence on the total marginal cost level, hence the assumed fuel price. Therefore, it has been decided to investigate the impact of the merit order effect on fuel price changes.

The basic approach taken in the sensitivity analysis is to vary the fuel price level, with all other influencing

[16] See http://ec.europa.eu/environment/climat/pdf/com_2010_86.pdf

FIGURE 15: SENSITIVITY AND MERIT ORDER CURVE OF THE REFERENCE SCENARIO

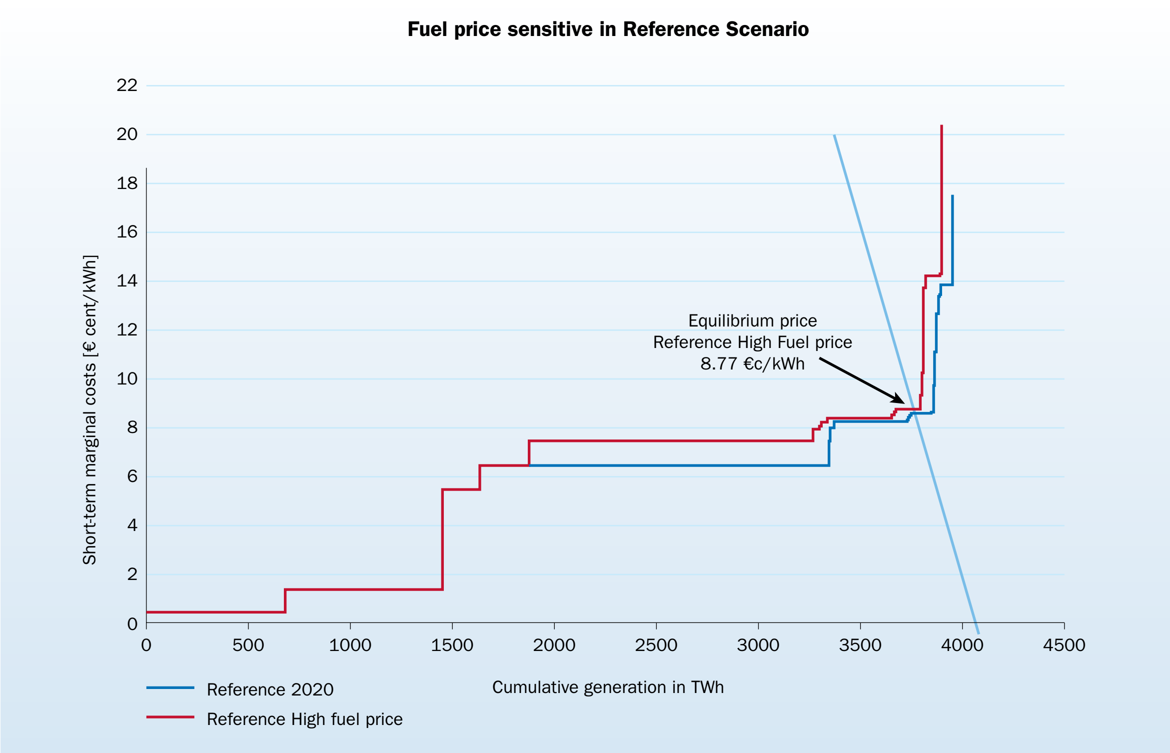


FIGURE 16: SENSITIVITY AND MERIT ORDER CURVE OF THE WIND SCENARIO

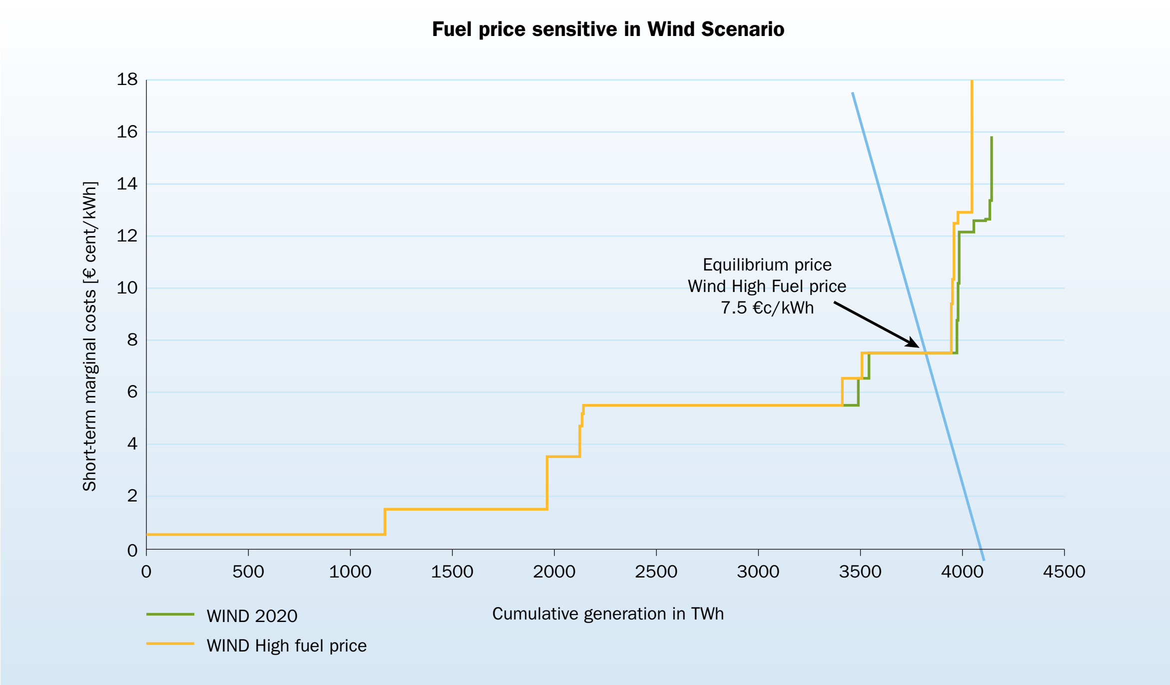


TABLE 5: INVESTMENT DEVELOPMENTS FOR THE DIFFERENT SCENARIOS AND SENSITIVITY ANALYSES

in MW	Reference 2020		Wind 2020		Reference High Fuel		Wind High Fuel	
	Policy based investments	Endogenous investments	Policy based investments	Endogenous investments	Policy based investments	Endogenous investments	Policy based investments	Endogenous investments
Coal	-96,458	187,183	-96,458	153,299	-96,458	177,895	-96,458	147,972
Gas	-35,486	4,993	-35,486		-35,486	9,633	-35,486	
Nuclear	-14,061		-14,061		-14,061		-14,061	
Wind			192,403				192,403	
Non-wind renewables	15,677		15,677		15,677		15,677	
Lignite	-28,068	8,793	-28,068	8,793	-28,068	8,793	-28,068	8,793
Fuel oil	-36,402		-36,402		-36,402		-36,402	
Other	1,269		1,269		1,269		1,269	
Total	-193,530	200,969	-1,127	162,092	-193,530	196,321	-1,127	156,765

"Policy based" investments are input assumptions and forced into the model, e.g. known investments and shut down due to age. "Endogenous" investments are simulated investments (according to long run marginal costs) found by the model in order to meet demand.

parameters remaining the same as in the base modelling analysis (introduced in the previous chapters). Fuel prices for conventional fuels - natural gas, coal and oil - have been increased by 25% in both scenarios, the Reference and the Wind Scenario.

In the two graphs above, the new marginal cost curves from the High Fuel scenarios can be observed in comparison to the original Base scenarios. Figure 15 represents the Reference case, the scenario with the same wind capacity as in 2008. The second graph, Figure 16, shows the Wind scenario, where wind capacities are significantly increased (by 200 GW), following EWEA's Pure Power "High" scenario.

The difference with the base analysis can be seen in the shifted marginal cost curves. Higher fuel prices lead to higher fuel costs and hence to short-run marginal costs for conventional fossil fuel technologies. This partly shifts the marginal cost curve up. At the same time, demand response leads to a very small decrease in overall demand, about 25 TWh in total. In the Reference scenario, the consequence is that the market's equilibrium price slightly increases to 8.77 €cent/kWh compared to 8.58 €cent/kWh in the base analysis.

However, in the Wind scenario, although the marginal cost curve shifts slightly, the market's equilibrium price stays at 7.5 €cent/kWh in the two modelling cases, the Base and the High Fuel price case. Here, in both scenarios, the same generation technology is marginal and incorporates the same short run marginal cost level.

As already described in the base analysis, the Wind scenario includes fewer investments in conventional capacity and less fossil fuel based power generation. Therefore, the merit order effect on fossil fuel price sensitivities would have been expected to be less significant in the Wind scenario than in the Reference scenario, as shown in the graph above. With higher fuel prices, the capacity investment development and fossil fuel generation is influenced in both scenarios. But the effects are much stronger in the Reference scenario because of its greater use of fossil fuel generation. Comparing endogenous investment in coal and natural gas in the base Reference Scenario and the High fuel Reference scenario shows that the High fuel price generally leads to more investment in gas (4,500 MW more) and less in coal (1,000 MW less).

This can be seen in Table 5. Consequently, fossil fuel generation in the High fuel price scenario is different - there is about 100 TWh more gas and 100 TWh less coal than in the Base case. The reason for this is that coal power technologies generally have higher long run marginal costs than gas technologies. With higher fuel prices and increasing costs, coal power technologies are more likely to become cost inefficient in the long term, making investments no longer feasible. Hence, an increase in fuel prices has a long-term effect: it increases long run marginal costs and so influences the investment and technology mix of the market equilibrium. Therefore the technology sequence of the marginal cost curve changes. And there is a short-term effect because increased fuel costs and short-run marginal costs shift the marginal costs curve up.

The increasing fuel prices are balanced out by decreasing carbon prices, however. Theoretically, a decrease in carbon prices would lead to a drop in marginal costs. As described in the clause above, the higher amounts of gas power generation and lower amounts of coal power generation in the High fuel price scenarios compared to the Base case leads to lower emission levels. Gas power generation is less CO_2 intensive than coal power generation. The overall emission cap is reached at lower CO_2 abatement cost levels which means a lower CO_2 price on the market.

Carbon prices in the High fuel price scenarios are about €5/tonne less than in the Base scenarios. The lower carbon price level in the Wind scenario means that short run marginal costs for the marginal technology are the same in the High fuel price case and in the Base case. The lower carbon price balances the higher fuel price so that short run marginal costs remain the same. Accordingly, the market's equilibrium price in the Wind scenario is the same in the High fuel price case and in the Base case.

The merit order effect, the difference in the short run marginal costs between the Reference scenario and the Wind scenario, is €12.7/MWh in the High fuel price case. When compared to the base analysis, the merit order effect increases by €1.9/MWh when fuel prices are increased by 25%.

TABLE 6: BELOW SUMMARISES THE RESULTS OF THE FUEL PRICE SENSITIVITIES

	Merit order effect	Volume order effect
	€/MWh	Billion €/a
Wind 2020	10.8	41.7
Wind high fuel	12.7	48.7

Table 6: Merit order effect and volume order effect for high fuel price sensitivity

TABLE 7: MODELLING RESULTS OF THE CARBON PRICE LEVEL FOR ALL SCENARIOS

	Base case		30% GHG reduction		High fuel prices	
	Reference	Wind	Reference	Wind	Reference	Wind
EUA price (in €/ton)	48.87	30	59.34	44.76	44.51	26.16
Power price (in €cent/kWh)	8.58	7.5	9.02	8.08	8.77	7.5
Merit order effect (in €/MWh)	10.8		9.4		12.7	

Table 7 shows the main results for the GHG reduction scenarios. It gives the resulting carbon price levels, the equilibrium power prices and the calculated merit order effect.

TABLE 8: MARKET POWER PRICES FOR THE GHG REDUCTION SENSITIVITIES

in €cent/kWh	Reference	Wind
Base case	8.58	7.5
30% GHG reduction	9.02	8.08
Relative price increase moving from Base case to		
30% GHG reduction	0.44	0.58

TABLE 9: VOLUME ORDER AND MERIT ORDER EFFECT FOR THE ANALYSED SENSITIVITIES

	Merit order effect	Volume order effect
	€/MWh	Billion €/a
Wind 2020	10.8	41.7
Wind high fuel	12.7	48.7
30% GHG reduction	9.4	35.7

Emission reduction target

Alongside fuel costs, another major influence on the short run marginal costs is the carbon costs, as they are affected by the emission reduction target. It was therefore decided to analyse the impact of the merit order effect on the assumed EU ETS cap, the scheme's overall emission reduction target for 2020.

The European Commission announced it would increase its ambition to cut carbon from a 20% to a 30% reduction by 2020 if a global international agreement for the post-Kyoto time period is reached. In addition, an impact assessment has been launched to assess the feasibility for a unilateral EU move to 30%. However, no quantified indications have been given as to how the 30% reduction target would be distributed between EU ETS and non-ETS sectors.

Our modelling assumptions for the base case, the 20% European emission reduction target, are a 21% reduction for the EU ETS sector compared to 2005 verified emissions. This is defined by the EU Commission and is based on the fact that ETS sectors represent roughly 40% of EU emissions and have a 60% share of the burden.

For the 30% target scenario, we assume that the ETS burden in its share of the total emission reduction volume remains constant at 60% of the total emission reduction volume. That translates to an ETS reduction target of 36% compared to 2005 levels. Furthermore, it is assumed that half of this is to be covered by external credits from non-EU projects.

Again, the approach of the sensitivity analysis has been to decrease the EU ETS cap in accordance with the percentages described above, leaving all other influencing variables constant.

The results show that increased wind power also reduces power prices when carbon emission reduction targets are higher.

When carbon price levels go up to €44/tonne, the general power market prices go up. It also leads to more gas capacity investments and higher gas generation volumes. This is mainly because gas generation is more competitive than coal due to its lower carbon intensity. And even in the Wind scenarios, the very ambitious GHG reduction targets cannot be met only by additional wind generation replacing some conventional power technologies. Supplementary gas power is also needed to replace coal power.

So, with increased wind power generation, gas technologies and gas power generation will be replaced by wind power.

In the 30% reduction target scenario, the higher carbon prices mean the general equilibrium prices for supply meeting demand also increase compared to the Base case with a 20% target. The Reference scenario in the 30% GHG reduction case results in an equilibrium price of €90.2 /MWh.

Moreover, the equilibrium prices are higher in the 30% reduction scenario than for the 20% scenario, see Table 8.

However, the impact of the market power price on the Wind scenario is greater than on the Reference scenarios. For example, the relative differences of the power market price for the Base case wind scenario (7.5 €cent/kWh) and the 30% GHG reduction scenario (8.08 €cent/kWh) is 0.58 €cent/kWh higher than for the Reference Scenario with 0.44 €cent/kWh. That means that the power market prices increase more when there is increased wind power and higher GHG emission reduction targets. And again, this refers to the fact that the higher the GHG reduction target, the more gas power generation (with higher short-run marginal costs than coal power) will be used, and this will have to be replaced by the increased wind power in the Wind scenarios.

In conclusion, the sensitivity analysis for the Reference and Wind scenarios illustrates higher equilibrium prices for the 30% reduction case than the 20% GHG base case. At the same time, the Wind scenario equilibrium price levels increase more than in the Reference scenarios. Since the merit order effect is calculated as the difference in equilibrium price between the Reference scenario and the Wind scenario, more ambitious GHG reduction targets will in general lead to lower merit order effects.

As depicted in Figure 17, the merit order effect in the 30% GHG reduction case is calculated at €9.4/MWh.

In Figure 18, all sensitivities previously analysed are summarised again. They related to the volume merit order effect as calculated for the base case analysis described on pages 132 and 134. Hence the figure represents the difference in the volume merit order effect for the two sensitivities, the 25% fuel price increase and the 30% GHG reduction compared to the base analysis accordingly.

The volume merit order effect of the 25% higher fuel

FIGURE 17: MERIT ORDER EFFECT OF THE ANALYSED SENSITIVITY CASES

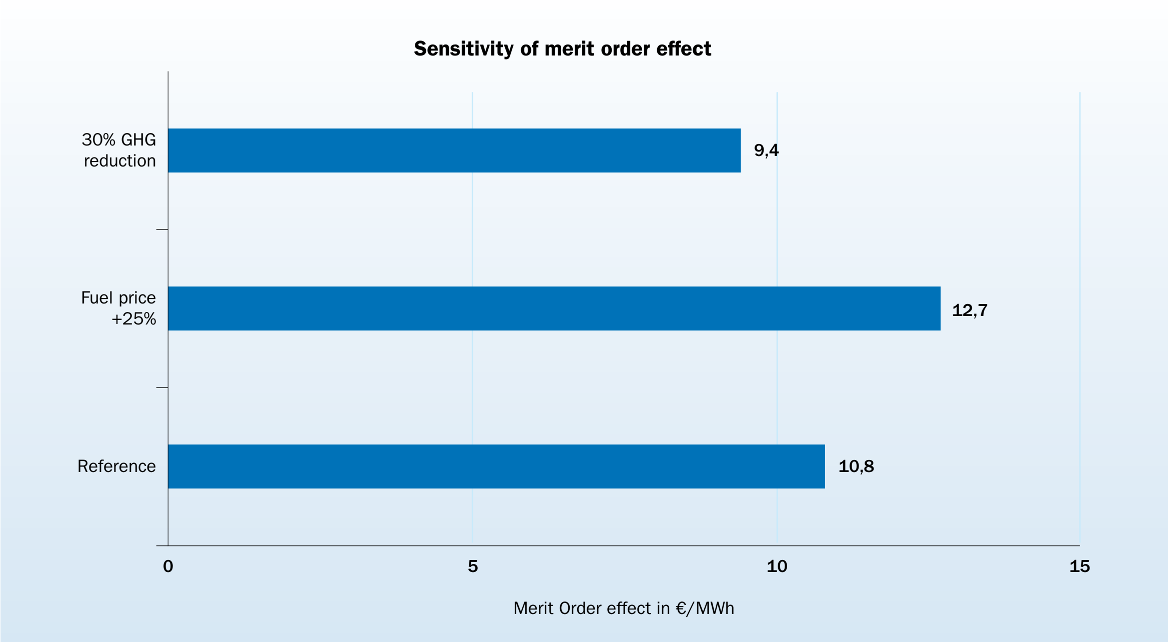
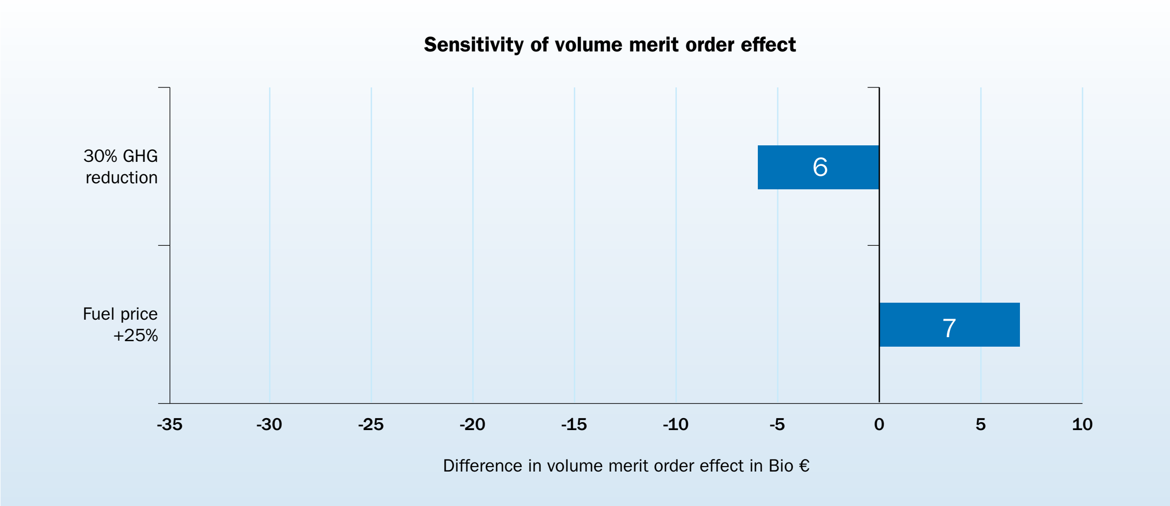


FIGURE 18: VOLUME MERIT ORDER EFFECT FOR THE DIFFERENT SENSITIVITIES



price case is €7 billion higher than the base case. The absolute values of the calculated volume order effect for the different sensitivities can be seen in the table below. The specific values are illustrated in the table and graph below.

6 CONCLUSION

The modelling analysis backs up the theory that increased wind power capacities will reduce power prices in the future European power market system.

It has been estimated that if wind power capacity increases by 200 GW in 2020 (reaching a total of 265 GW), this would give a merit order effect of €10.8 / MWh, reducing the average wholesale power price level from €85.8/MWh to €75/MWh.

However, this figure assumes a fully functioning market. It also includes the long-term investments forecast and is therefore based on the long-term market equilibrium. Simulated generation volumes in 2020 require economic feasibility with regards to long run marginal costs. Wind capacity replaces the least cost efficient conventional capacities so that the system is in equilibrium. This shift in the technology mix is the main reason for the observed merit order effect.

In reality this might not always happen. Power market bids are based on short run marginal costs, plants that are not cost efficient might be needed in extreme situations, for example when there is a lot of wind power on the system. The short-term effects of wind power are mostly related to the variability of wind power. The responding price volatility due to increased wind power stresses the cost efficiency of wind power generation. And in the real world, this would lead to a smaller merit order effect than analysed in the future optimal market equilibrium.

Consequently, the results of the study have to be considered carefully, especially considering the assumed future capacity mix, which includes a lot of uncertainties. Moreover, results should not be directly compared to recent literature, which usually estimate the short-term price effects of wind power. Here the market is not always in equilibrium and actual price differences and the merit order effect might therefore be very different.

Moreover, the study estimates the volume merit order effect referring to the total savings brought about due to wind power penetration during a particular year. Assuming that the entire power demand is purchased at the marginal cost of production, the overall volume of the MOE has been calculated at €41.7 billion/year. But this should not be seen as a purely socio-economic benefit. A certain volume of this is redistributed from producer to consumer because decreased prices mean less income for power producers. Currently, only the long-term marginal generation which is replaced by wind has a real economic benefit, and this should be contrasted to the public support for extended wind power generation.

The scenarios were developed so that the modelling analysis could show the effect of the additional wind capacities on future power prices. For this reason, the main difference between the two scenarios is the amount of wind capacity. All other renewable sources and capacities have been kept at 2008 levels in both scenarios. Hence, there is no future capacity increase assumed for bio-energy, solar or geothermal energy resources. This, however, does not reflect a very realistic market development. A higher renewable share would influence the abatement costs to reach the defined CO_2 emissions cap. Indirectly, this would also influence investment decisions in conventional fossil-based technologies, especially in the Reference scenarios. However, it is difficult to estimate the outcome on the merit order effect. Lower emission levels and hence lower carbon prices might also lead to coal power becoming more cost-efficient. This might counteract the effect of renewables on emissions. It is therefore recommended that these impacts be studied in a more thorough sensitivity analysis with the help of a quantifying modelling tool.

The sensitivity analysis resulted in an increase of the merit order effect by €1.9 /MWh when fossil fuel prices (gas, coal and oil) are increased by 25%. In the High fuel price case, wind power makes the power price drop from €87.7/MWh in the Reference scenario to €75/MWh in the Wind scenario. Comparing the resulting merit order effect in the High fuel case of €12.7/MWh to the Base case results of €10.8/MWh, the 25% higher fuel price case gives a merit order effect that is 17.5% higher.

The study showed that fuel prices have a major influence on power prices and marginal cost levels. The merit order effect has been mostly explained by the difference in the technology capacity and generation mix in the various scenarios, especially the differences in the development and utilisation of coal and gas power technologies. Investigating fuel price differences is therefore highly relevant. However, even stronger impacts on the merit order effect might be observed by changing the relative price differences of gas and coal price levels.

The study proved that carbon market assumptions and especially the resulting carbon price level will be a very important variable for the future power market and its price levels. Regarding the sensitivity of the assumed GHG emissions reduction target, the analysis illustrated higher equilibrium prices for the 30% reduction case than for the 20% reduction base case.

However, the results of the sensitivity analysis do very much depend on the assumptions for future abatement potential and costs in all EU ETS sectors, as well as in the industrial sectors.

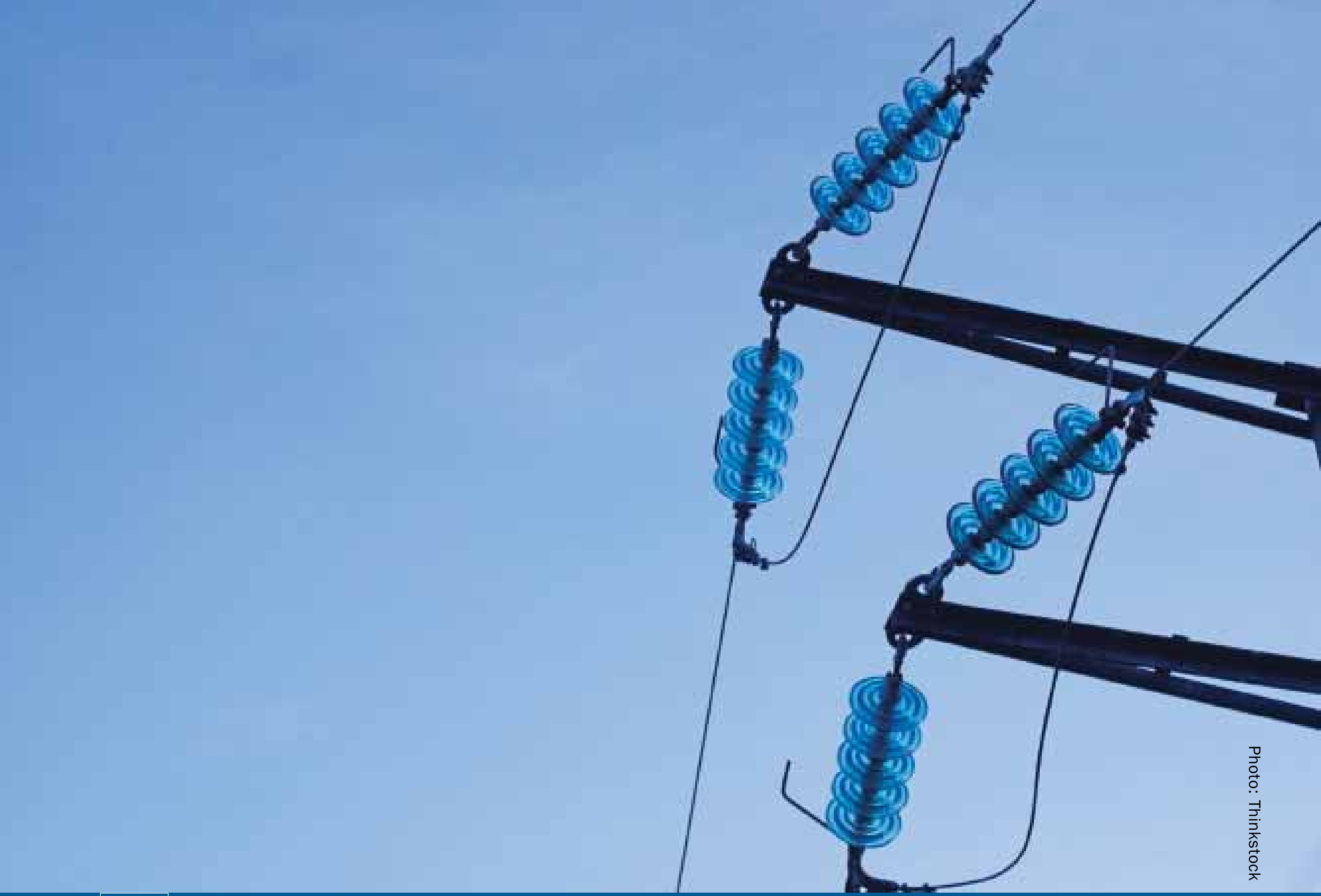


Photo: Thinkstock

7 ANNEX

7.1 Assumptions in the model

Fuel prices

Fuel prices and other input factors such as efficiency are important for the Classic Carbon model in that they determine the cost of electricity, and also affect how power systems will look in the future. In this chapter, we outline the most important supply side assumptions in the model, and their effect on future capacity.

Fuel price assumptions for both scenarios in the model year 2020 are outlined below in Table 10.

Renewable capacities

In general, the capacity development in the Classic Carbon model is partly determined exogenously, i.e. outside the model, and put into the simulations as input, and partly determined endogenously, i.e. by the model. Endogenous investments are based on the profitability of the investments, whereas exogenous investments (as well as decommissioning of capacity) are based on known decisions and policy driven actions. Therefore, endogenous investments are also called "market based" and exogenous investments are named "policy based".

In both scenarios, the wind capacity development is determined exogenously. This means that, absolute figures for installed wind capacities in 2020 are defined externally and typed into the model as fixed data input.

TABLE 10: FUEL PRICE ASSUMPTIONS (2008 REAL PRICES)

	Coal €/MWh	Natural gas €/MWh
2008	7	12.5
2020	11	29

Fuel price assumptions for 2020 come from the International Energy Agency.[17]

Furthermore, all other renewable technologies, solar, wind and bio-energy are kept constant at the 2008 level in both scenarios. This might seem unrealistic because they should be considered as policy based investments which would happen according to already implemented support schemes. However, we did not add any exogenous capacities for renewable energy technologies other than wind in order to determine the pure merit order effect of wind power investments only. Additional policy based investments in other renewable technologies might be considered as "business as usual", but would also lead to a decrease in average power prices as long they replaced some more expensive conventional technologies. This would distort the results and the merit order effect of wind power. Since this study was supposed to only investigate the merit order effect of wind power it restricted policy based investments in other renewable technologies.

The following table indicates the assumed wind power capacities for the two scenarios. The Reference scenario uses 2008 values. The installed capacities given for the Wind scenario represent the high values from EWEA's Pure Power scenarios.

Power demand

The following demand input data for 2020 was provided by EWEA[18].

The demand modelling in the Classic Carbon model is detailed and advanced since the model uses a flexible demand approach (that is, a demand that can react

in MW		Austria	Belgium	Bulgary	Cyprus	Czech R.	Denmark	Estonia	Finland	France	Germany	Greece	Hungary	Ireland	Italy
Reference Scenario	onshore	995	354	158	0	150	2,771	78	119	3,404	23,891	985	127	977	3,736
	offshore		30				409		24		12			25	
Wind Scenario	onshore	4,000	2,500	3,500	500	1,800	4,000	500	2,000	20,000	42,000	8,300	1,200	6,000	17,000
	offshore		2,000				2,500	100	1,000	6,000	10,000	200		1,000	1,000

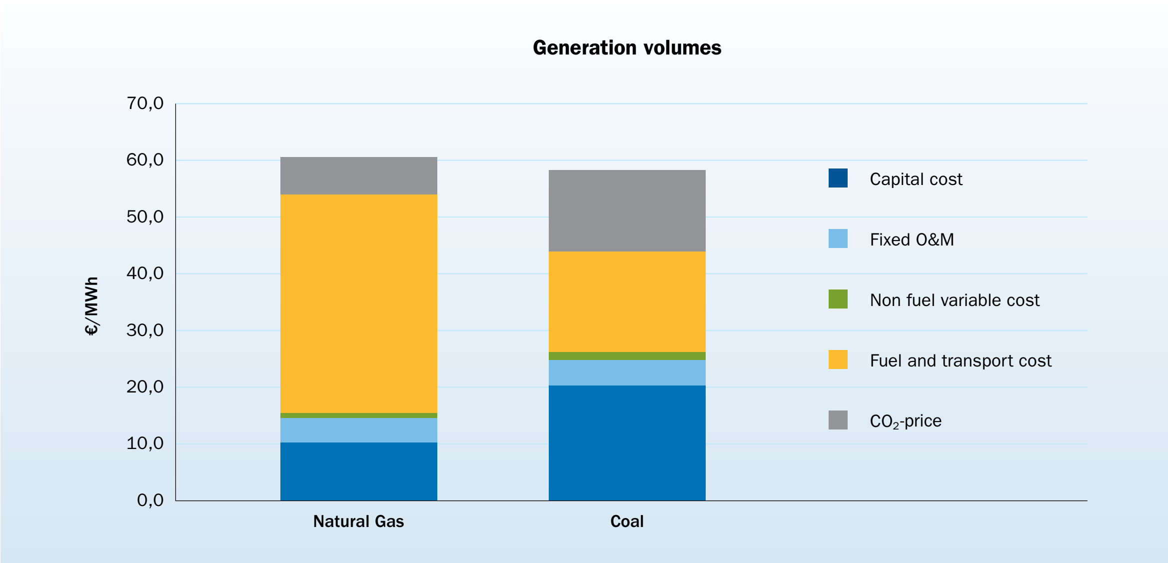
		Latvia	Lithuania	Luxemb.	Malta	Netherl.	Poland	Portugal	Romania	Slovakia	Sllovenia	Spain	Sweden	UK	Total
Reference Scenario	onshore	27	54	35	0	1,978	472	2,862	10	3	0	16,740	888	2,650	64,935
	offshore					247							133	591	
Wind Scenario	onshore	200	1,000	700	200	4,400	12,000	9,000	3,500	1,000	700	41,000	8,000	14,000	265,000
	offshore	100	100			6,000	500	0	0			1,500	3,000	20,000	

in TWh	Austria	Belgium	Bulgary	Cyprus	Czech R.	Denmark	Estonia	Finland	France	Germany	Greece	Hungary	Ireland	Italy
Demand in 2020	78	109	56	7	103	40	15	102	633	674	80	53	37	442
	Latvia	Lithuania	Luxemb.	Malta	Netherl.	Poland	Portugal	Romania	Slovakia	Sllovenia	Spain	Sweden	UK	Total
	9	21	4	2	152	204	77	93	43	18	387	187	452	4,079

[17] IEA World Energy Outlook 2009 – in combination with assumptions of the New Energy Policy scenario found in: "An EU ENERGY SECURITY AND SOLIDARITY ACTIO_ PLAN Europe's current and future energy position Demand – resources – investments" {COM(2008) 781 final}

[18] The figures refer to the calculations for EWEA's Pure Power Scenarios and derive from Trends to 2030 (electricity generation minus net imports).

FIGURE 19: LONG-TERM MARGINAL COSTS FOR COAL-FIRED AND GAS-FIRED PLANTS IN GERMANY 2020



to prices). The demand data input above is given exogenously. The model then calculates the actual demand in accordance with specified income and price elasticity[19].

Investments

In both scenarios, wind and other renewable capacities are fixed, as described on page 142. But the Classic Carbon model contains a module that generates investments in electricity capacity based on the gap between supply and demand.

Hence, if the exogenous given capacity development is not sufficient to meet power demand, the model would determine the additional investments needed endogenously. The general logic behind endogenous investment decisions is that if the price of electricity exceeds the long-term marginal cost of the least expensive conventional technology, there will be investment in this technology. The overall costs of each technology depend on the technology's capital costs, fuel costs, efficiency, CO_2 costs, fuel transport costs and other variable and fixed costs. Investments are, subject to restrictions, usually made in coal-fired or gas-fired capacity.

However, conventional investments are restricted in two main aspects. First, the model restricts endogenous investments in nuclear, as developments in these technologies tend to be influenced to a large degree by politics. Second, the potential investment levels and investment technologies are capped for each country according to the existing capacity profile so that the model cannot define unlimited investments in only one technology.

Figure 19 compares the assumed long-run marginal costs for new CCGT and new coal-fired capacity for Germany in 2020. The figure is based on the assumption that a CCGT unit is run with an availability of 85% whereas a coal condensing unit is run with a slightly higher availability, 90%.[20] With the applied assumptions, coal is the least-costly technology in 2020. As fuel transportation cost is the only component that varies between the countries, it can be deduced that most capacity investments in Western Europe generated by Classic are in coal capacity, given the fuel and CO_2 prices that the

[19] Price elasticities are an expression for a percentage change in demand following a percentage change in price. For example, if demand drops by 0.5% following a 1% price increase, the price elasticity equals 0.5. The elasticity is therefore a measure for how flexible (or sensitive) the demand is with respect to price changes.

[20] The availability of a condensing unit in the classic model is a model result and could thus deviate from the assumptions in above figure.

figure is based on. The CO_2 estimates are a result of the model runs, and will thus depend on the investment mix in Europe. With increased investments in coal-fired generation, the CO_2 price will increase, though the price effect will depend on allocations.

The carbon market

Both scenarios apply the EU's basic target of 20% emission reductions (compared to 1990 levels) by 2020. Furthermore, the version of the EU Commission's draft amendment that has been approved by the Parliament has been used for the basic assumptions about allocation and trading rules in 2020[21]. In this recent regulation, a lot of clarification is given concerning allocation and auctioning rules. However, due to some outstanding definitions and specifications, uncertainties on the interpretation of these regulations still exist. These uncertainties in the allocation regulations are dealt with by defining simple, Europe-wide assumptions to quantify the total allocation, the auctioning volume and the import volume of external credits.

Furthermore, it is assumed that existing ETS sectors will have to reduce emissions by 21% by 2020 compared to 2005 levels. In future, CO_2 emissions from aviation, CO_2 and N_2O emissions from some chemical processes, and GHG emissions from capturing, transporting and storing will be included in the ETS. The new sectors are also included and get the same reduction target of 21%.

The European Commission has determined a single EU wide cap and decided that allowances will be allocated on the basis of harmonised rules. Consequently, the overall allocation volume is based on the 2005 emissions of the scheme's included installations and will go down in a linear manner by 1.74% each year.

A maximum credit import limit of 1.6 billion tonnes over the period 2008-2020 is assumed. This figure corresponds to the European Commission's estimated total import volume. The proposal in the draft ETS

TABLE 11: MODEL ASSUMPTIONS ON EU ETS ALLOCATION VOLUME IN 2020

			Mt
ETS sectors' emissions in 2005			2,141
ETS sectors' allocation in 2020		(-21%)	1,692
New sectors' emissions in 2005			253
	Aviation		156
	Chemicals		85
	Aluminium		12
New sectors' allocation in 2020		(-21%)	200

Directive is that no further imports of CERs/ERUs will be allowed unless an international post-Kyoto agreement enters into force. CERs/ERUs which are not used for compliance in the 2008-2012 trading period may be carried over to the third trading period. In 2013-2020, the average credit import is assumed to be 106 million tonnes per year.

7.2 Model description

The results presented in the merit order study above were obtained using the Pöyry Classic Carbon model. The model is a long-term power and carbon market simulation model that in addition to power prices and flows also calculates investments needed to meet the assumed demand. Investments are calculated based on short run marginal costs and fixed investment costs. For the model runs we added the amount of wind investments assumed for this study, and let the model fill the remaining gap between demand and capacity.

The geographic scope of the model includes most of Europe. The time resolution of the model is monthly, while each month is divided into five different load blocks. The Classic Carbon model is a perfect foresight model; it does not model stochasticity in wind and does not have an hourly time resolution.

[21] The amended Directive has been approved by the EU Parliament in December 2008. See http://www.consilium.europa.eu/ueDocs/cms_Data/docs/pressData/en/ec/104692.pdf

The Classic Carbon model is an advanced model simulation tool for the analysis of the power and carbon market. The model is a combination of a bottom-up and a top-down model, capturing the fundamental supply and demand functions in the power and carbon market. It is an extension of Pöyry's power market model, CLASSIC.

As the name suggests, CLASSIC is Pöyry's first and oldest power market model. It has been expanded and developed over a period of more than 15 years, and has grown with the market. It is designed to model the long-term market developments, including power prices, demand, generation, investments, trade and CO_2 emissions. CLASSIC models the whole European power market (EU 25 + Norway and Switzerland), and has been used to analyse developments in the European power market, in particular price developments, demand developments, investments in different types of power generation, and trade between regions. CLASSIC combines an advanced simulation algorithm for the European power market with speed and user-friendliness. CLASSIC's user interface is Excel, where both the input data and the results from the simulation are presented in a menu-based format where users can easily enter and extract the information they require, and analyse them in the form of tables and/or graphs.

The mathematical programming components of CLASSIC are implemented in The General Algebraic Modelling System GAMS, with CLASSIC's Excel interface controlling all the aspects of the communication and running of the GAMS components. Thus the use of CLASSIC requires only a standard knowledge of Excel, and the user does not need to have any knowledge of GAMS or mathematical programming.

Technical features of CLASSIC

Geographical scope

In the standard version of CLASSIC, all European countries (EU 27 + Norway and Switzerland) are modelled simultaneously. Denmark is further split into two regions, Jutland and Zealand. Small countries (for example Cyprus, Malta) and some countries in Eastern Europe may be excluded. It is easy to expand or reduce the number of countries in the model.[22]

Time structure

Simulations in CLASSIC are run on a two-level time resolution. The simulation period is divided up into one or more time periods, such as quarters, months or weeks. Each period is then divided up into up to five load blocks. The load blocks represent the varying load levels experienced in each period and generally correspond to times of the day, such as night, weekend day, evening, day-time peak, etc. Unlike the periods, the load blocks are not sequential (that is, load block 2 does not follow load block 1 in time for example).

Both the period and load-block resolution are user-definable. The user simply specifies the length of each period (which can be of unequal length), and the hours in a typical week that are mapped to each load block, and ensures the data corresponds to these definitions.

Supply

The model includes relevant data for existing generation technologies and fuel and other operational costs. Conventional thermal capacity is called into production whenever market prices cover marginal bids.

Rather than model each individual plant within a given region, CLASSIC specifies the generation set at the plant type level of detail. Each plant type has several general technical properties (such as costs) that are constant, and other technical properties (such as capacities and efficiencies) that differ by country. The plant type approach has been adopted for the following reasons:

In general there is insufficient data to model all plants at the same level of detail and data accuracy.

[22] The model also uses an external "region" to enable the modeling of electricity trade into and out of the European region (for example trade between Russia and Finland). The data set for this external region consists of cross border transmission capacities to and from the external region, fixed transmission flows to and from the external region, and/or user defined electricity prices for the external region that is used when determining price-based trade flows with the external region.

Within an economic (rather than detailed technical) modelling framework, the addition of many individual plants adds to the computational burden (often significantly) without providing much additional accuracy. In combination with the lack of data issue, any additional accuracy that appears to be provided is often spurious, at best, or incorrect at worst.

Wind production and CHP production are represented by production profiles based on statistical data. Regarding CHP, the model allows advanced CHP modelling, and both extraction and backpressure technologies are modelled separately.[23] The latter category is further divided into public and industrial CHP.

In the context of the Nordic power market or markets with large hydro reservoirs (e.g. the Alpine region), it is crucial to represent hydropower with reservoirs in an adequate manner, that is, to take into account the system's ability to store water over longer periods of time. For example, while inflows peak in the summer when the snow melts and in the autumn when precipitation comes in the form of rain, demand peaks in the winter. Hence, hydropower generators store water and, at any given time, will supply according to current reservoir levels and expectations about future inflow and prices. In order to capture this feature, CLASSIC optimises the use of water over the year, taking inflow and reservoir constraints into account.

Demand

The demand modelling in CLASSIC is detailed and advanced, since demand is equally important to supply. The most important feature in this respect is that CLASSIC uses a flexible demand (that is, a demand that can react to prices). Many other models, for example, fix the demand level exogenously, meaning that the demand levels are specified by the user. By contrast, CLASSIC calculates the demand within the model, and the user only specifies demand flexibility in terms of so-called elasticities and a calibration point, which is usually a pair of observed price and demand level. The model then assumes a so-called Cobb-Douglas demand function as a mathematical form for the demand.[24] If the user lacks data for demand flexibility, the demand can optionally also be fixed.

In addition, the model allows specification of up to five demand groups, each with its own demand curve. At the moment, those five groups are households, power intensive industry, service industry, other industry and electric boilers. The latter category is of importance in the Nordic context.

Furthermore, the user specifies demand shapes over the year and over the day (by using load blocks) for each of the demand groups. For each demand group, the user also specifies mark-ups, taxes, distribution costs, VAT levels and so on.

Transmission structure

Cross border transmission is modelled from an economic standpoint (rather than via a physical load-flow approach), with each connection from any one region to any other region having a specified (linear) loss, cost, availability, and capacity.

In general, CLASSIC allows three types of inter-regional transmission:

- Normally the transmission is price-based, that is, transmission between regions is based on price differences (the price includes losses and transmission fees).
- The transmission can be fixed between regions based on contracts between the regions (for example Finland and Russia).
- Transmission can be a combination of the price-based and fixed. In this case CLASSIC allocates the line capacity required for the fixed trade flows to the fixed trade, and only the remainder of the capacity is available for price-based trade.

Within a given country, CLASSIC assumes there are no transmission bottlenecks. Internal transmission and distribution losses, however, are accounted for by using linear loss functions, with user specified parameters.

[23] Backpressure plants are characterised by a fixed relationship between heat and electricity generation. Extraction technologies, on the other hand, are to a certain extend flexible in this respect, and the heat generation gives constraints on the electricity generation, without determining it.

[24] This class of functions is most commonly used in economics.

Market power modelling

Although based on the assumption of a perfectly competitive market, CLASSIC is also able to capture the effects of market dynamics. In a perfectly competitive market, producers bid in their marginal production costs. Under the assumption of market power, the producer bids in a price that is above its marginal costs. In CLASSIC, this can be captured by defining bid-mark-ups, which can be defined both in relative (percentage of marginal costs) or absolute terms. In this context it should be noted that those bid-mark-ups are exogenous, that is, they are defined by the user.[25]

Investment modelling

CLASSIC is well suited for long-term power market modelling. For such modelling, future investments in the generation park are crucial. Sometimes, investments are known in advance. In this case the user can specify the investments that will come on-line for each region and plant group.

However, not all future investments are known. In this case, the model calculates the investment levels, that is, the investments are an output from the model. For example, running the model for 20 years ahead, a typical output would be how many investments in, say, combined cycle gas turbines (CCGT), are coming online over the next 20 years. In order for the model to calculate the coming investments, the user specifies an investment potential for each country and plant group, and the investment costs.

The model also calculates refurbishments of plants that are retiring. The retirements have to be specified by the user, as well as refurbishment costs.

Scenario modelling

A flexible scenario structure is used to enable the specification of a “base” set of data and then multiple scenarios that may differ in only a small number of aspects from the base data. The base data and a scenario data set are combined to the model data, which is used for the simulations and the analysis. The base data set is residing in the main model, and each scenario has a corresponding data worksheet in which the altered data is stored.

[25] In a market power model, the bid-mark-ups would be endogenous, i.e. the model would calculate the level of bid-mark-ups based on market dynamics and other features like uncertainty.

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ACTIVE POWER	Is a real component of the apparent power, usually expressed in kilowatts (kW) or megawatts (MW), in contrast to REACTIVE POWER (UCTE).
ADEQUACY	A measure of the ability of the power system to supply the aggregate electric power and energy requirements to the customers within component ratings and voltage limits, taking into account planned and unplanned outages of system components. Adequacy measures the capability of the power system to supply the load in all the steady states in which the power system may exist considering standards conditions (CIGRE definition).
ANCILLARY SERVICES	Are Interconnected Operations Services identified as necessary to perform a transfer of electricity between purchasing and selling entities (TRANSMISSION) and which a provider of TRANSMISSION services must include in an open access transmission tariff (UCTE).
CAPACITY	Is the rated continuous load-carrying ability of generation, transmission, or other electrical equipment, expressed in megawatts (MW) for ACTIVE POWER or megavolt-amperes (MVA) for APPARENT POWER (UCTE).
CAPACITY CREDIT	See CAPACITY VALUE
CAPACITY FACTOR	(load factor) Is the ratio between the average generated power in a given period and the installed (rated) power.
CAPACITY VALUE	Also denoted as CAPACITY CREDIT of installed wind power capacity measures the amount of conventional generation that can be replaced by wind power capacity while maintaining existing level of supply security.
CONTINGENCY	Is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A CONTINGENCY also may include multiple components, which are related by situations leading to simultaneous component outages (UCTE).
CONTROL AREA	Is a coherent part of the ENTSO-E INTERCONNECTED SYSTEM (usually coincident with the territory of a company, a country or a geographical area, physically demarcated by the position of points for measurement of the interchanged power and energy to the remaining interconnected network), operated by a single TSO, with physical loads and controllable generation units connected within the CONTROL AREA. A CONTROL AREA may be a coherent part of a CONTROL BLOCK that has its own subordinate control in the hierarchy of SECONDARY CONTROL (UCTE).
CONTROL BLOCK	Comprises one or more CONTROL AREAS, working together in the SECONDARY CONTROL function, with respect to the other CONTROL BLOCKS of the SYNCHRONOUS AREA it belongs to (UCTE).
CURTAILMENT	Means a reduction in the scheduled capacity or energy delivery (UCTE).
DYNAMIC LINE RATING	Controlled adaptation of transmission line rating as a function of continuously measured line temperature.

GATE CLOSURE	Is the point in time when generation and demand schedules are notified to the system operator.
INERTIA	Of a power system is the sum of all rotating mass inertias of the connected generation opposing a change of system frequency. The rotational speed of synchronous generators is an exact representation of the system frequency. In the very first moments after loss of generation the inertia of the rotating machinery helps to keep the system running.
INTERCONNECTED SYSTEM	An INTERCONNECTED SYSTEM is a system consisting of two or more individual electric systems that normally operate in synchronism and are physically connected via TIE-LINES, see also: SYNCHRONOUS AREA (UCTE).
INTERCONNECTION	An INTERCONNECTION is a transmission link (e.g. TIE-LINE or transformer) which connects two CONTROL AREAS (UCTE).
LOAD	Means an end-use device or customer that receives power from the electric system. LOAD should not be confused with DEMAND, which is the measure of power that a load receives or requires. LOAD is often wrongly used as a synonym for DEMAND (UCTE).
LOAD FACTOR	See CAPACITY FACTOR
MINUTE RESERVE	{15 Minute Reserve} See: TERTIARY CONTROL RESERVE
N-1 CRITERION	The N-1 CRITERION is a rule according to which elements remaining in operation after failure of a single network element (such as transmission line / transformer or generating unit, or in certain instances a busbar) must be capable of accommodating the change of flows in the network caused by that single failure (UCTE).
N-1 SAFETY	Means that any single element in the power system may fail without causing a succession of other failures leading to a total system collapse. Together with avoiding constant overloading of grid elements, (N-1)-safety is a main concern for the grid operator.
NET TRANSFER CAPACITY	Maximum value of generation that can be wheeled through the interface between the two systems, which does not lead to network constraints in either system, respecting technical uncertainties on future network conditions.
POWER CURVE	Relationship between net electric output of a wind turbine and the wind speed measured at hub height on 10 min average basis.
PRIMARY CONTROL	Maintains the balance between GENERATION and DEMAND in the network using turbine speed governors. PRIMARY CONTROL is an automatic decentralised function of the turbine governor to adjust the generator output of a unit as a consequence of a FREQUENCY DEVIATION / OFFSET in the SYNCHRONOUS AREA: PRIMARY CONTROL should be distributed as evenly as possible over units in operation in the SYNCHRONOUS AREA.

PRIMARY CONTROL RESERVE	It is the (positive / negative) part of the PRIMARY CONTROL RANGE measured from the working point prior to the disturbance up to the maximum PRIMARY CONTROL POWER (taking account of a limiter). The concept of the PRIMARY CONTROL RESERVE applies to each generator, each CONTROL AREA / BLOCK, and the entire SYNCHRONOUS AREA (UCTE).
PX	Is a Power Exchange Scheduling Coordinator, and is independent of System Operators and all other market participants.
REACTIVE POWER	Is an imaginary component of the apparent power. It is usually expressed in kilo-vars (kVAr) or mega-vars (MVAr). REACTIVE POWER is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. REACTIVE POWER must be supplied to most types of magnetic equipment, such as motors and transformers and causes reactive losses on transmission facilities. REACTIVE POWER is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors, and directly influences the electric system voltage. The REACTIVE POWER is the imaginary part of the complex product of voltage and current (UCTE).
RELIABILITY	Describes the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. RELIABILITY on the transmission level may be measured by the frequency, duration, and magnitude (or the probability) of adverse effects on the electric supply / transport / generation. Electric system RELIABILITY can be addressed by considering two basic and functional aspects of the electric system: Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. Security — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements (UCTE).
SECONDARY CONTROL	Is a centralised automatic function to regulate the generation in a CONTROL AREA based on SECONDARY CONTROL RESERVES in order to maintain its interchange power flow at the CONTROL PROGRAM with all other CONTROL AREAS (and to correct the loss of capacity in a CONTROL AREA affected by a loss of production) and, at the same time, (in case of a major FREQUENCY DEVIATION originating from the CONTROL AREA, particularly after the loss of a large generation unit) to restore the frequency in case of a FREQUENCY DEVIATION originating from the CONTROL AREA to its set value in order to free the capacity engaged by the PRIMARY CONTROL (and to restore the PRIMARY CONTROL RESERVES).
SECURITY LIMITS	Define the acceptable operating boundaries (thermal, voltage and stability limits). The TSO must have defined SECURITY LIMITS for its own network. The TSO shall ensure adherence to these SECURITY LIMITS. Violation of SECURITY LIMITS for prolonged time could cause damage and/or an outage of another element that can cause further deterioration of system operating conditions (UCTE).

STABILITY	Is the ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.
STATIC LOAD FLOW CALCULATIONS	Investigate the risk of system overload, voltage instability and (N-1)-safety problems. System overload occurs when the transmitted power through certain lines or transformers is above the capacity of these lines/transformers. System static voltage instability may be caused by a high reactive power demand of wind turbines. Generally speaking, a high reactive power demand causes the system voltage to drop.
SYNCHRONOUS AREA	Is an area covered by INTERCONNECTED SYSTEMS whose CONTROL AREAS are synchronously interconnected with CONTROL AREAS of members of the association. Within a SYNCHRONOUS AREA the SYSTEM FREQUENCY is common on a steady state. A certain number of SYNCHRONOUS AREAS may exist in parallel on a temporal or permanent basis. A SYNCHRONOUS AREA is a set of synchronously INTERCONNECTED SYSTEMS that has no synchronous interconnections to any other INTERCONNECTED SYSTEMS, see also: UCTE SYNCHRONOUS AREA (UCTE).
SYSTEM FREQUENCY	Is the electric frequency of the system that can be measured in all network areas of the SYNCHRONOUS AREA under the assumption of a coherent value for the system in the time frame of seconds (with minor differences between different measurement locations only) (UCTE).
TERTIARY CONTROL	Is any (automatic or) manual change in the working points of generators (mainly by re-scheduling), in order to restore an adequate SECONDARY CONTROL RESERVE at the right time (UCTE). The power which can be connected (automatically or) manually under TERTIARY CONTROL, in order to provide an adequate SECONDARY CONTROL RESERVE, is known as the TERTIARY CONTROL RESERVE or MINUTE RESERVE. This reserve must be used in such a way that it will contribute to the restoration of the SECONDARY CONTROL RANGE when required; The restoration of an adequate SECONDARY CONTROL RANGE may take, for example, up to 15 minutes, whereas TERTIARY CONTROL for the optimisation of the network and generating system will not necessarily be complete after this time (UCTE).
TRANSIENT STABILITY	The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance of specified severity and to regain a state of equilibrium following that disturbance (UCTE).
TRANSMISSION SYSTEM OPERATOR	Is a company that is responsible for operating, maintaining and developing the transmission system for a CONTROL AREA and its INTERCONNECTIONS (UCTE).

- ***AC*** Alternating Current
- ***ACER*** Agency for Coordination of Energy Regulation
- ***CAES*** Compressed Air Energy Storage
- ***CHP*** Combined Heat and Power
- ***DFIG*** Doubly Fed Induction Generator
- ***DG*** Distributed Generation
- ***DSM*** Demand Side Management
- ***DSO*** Distribution System Operator
- ***EEX*** European Energy Exchange
- ***EEZ*** Exclusive Economic Zone (offshore)
- ***ENTSO-E*** European Network for Transmission System Operators for Electricity
- ***ERGEG*** European Regulators for Energy and Gas
- ***EU*** European Union
- ***EUA*** European Union Allowances
- ***EU ETS*** European Emission Trading Scheme
- ***EUR*** Euro
- ***EWIS*** European Wind Integration Study
- ***FACT*** Flexible AC Transmission System Device
- ***FRT*** Fault Ride Through
- ***GGCF*** Generic Grid Code Format
- ***GHG*** Greenhouse Gases
- ***GW*** Gigawatt
- ***GWh*** Gigawatt hour
- ***HVAC*** High voltage AC
- ***HVDC*** High voltage DC
- ***HVDC CSC*** High voltage DC with Current Source Converters
- ***HVDC LCC*** High voltage DC with Line Commutated Converters
- ***HVDC VSC*** High voltage DC with Voltage Source Converters
- ***ICT*** information and communication technology
- ***IEC*** International Electrotechnical Committee
- ***IGBT*** Insulated Gate Bipolar Transistor
- ***ISO*** Independent System Operator
- ***IPP*** Independent Power Producer
- ***KWh*** Kilo Watt Hour
- ***LCC*** Line Commutated Converter
- ***MIBEL*** Mercado Ibérico de Electricidade (Iberian Electricity Market)
- ***MOE*** Merit Order Effect
- ***MVAR*** Mega Volt Ampere Reactive
- ***MW*** Megawatt
- ***MWh*** Megawatt hour
- ***RE*** Renewable Energy
- ***RES*** Renewable Energy Sources
- ***NRMSE*** Normalised Root Mean Square Error
- ***NTC*** Net Transfer Capacity
- ***NWP*** Numerical Weather Prediction
- ***OTC*** Over-The-Counter Markets
- ***PAC*** Pumped Hydro Accumulation Storage
- ***PMSG*** Permanent Magnet Synchronous Generator
- ***RMSE*** Root Mean Square Error
- ***SAF*** System Adequacy Forecast
- ***SCADA*** Supervisory Control and Data Acquisition
- ***SCIG*** Squirrel Cage Induction Generator
- ***SVC*** Static Var Compensator
- ***TEN-E*** Trans-European Networks Energy
- ***TSO*** Transmission System Operator
- ***TW*** Terawatt
- ***TWh*** Terawatt hour
- ***TYNDP*** Ten Year Network Development Plan
- ***UCTE*** (previous) Union for the Coordination of Transmission of Electricity (presently dissolved into ENTSO-E)
- ***VPP*** Virtual Power Plant
- ***VSC*** Voltage Source Converter
- ***WAMS*** Wide Area Monitoring System
- ***WEPP*** Wind Energy Power Plant
- ***WRIG*** Wound Rotor Induction Generator

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