CIGRE Technical Brochure on

Grid Integration of Wind Generation

Working Group 08

of Study Committee C6

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ABSTRACT

Wind energy will play in the future an important role world wide for energy production in the after oil era. This fluctuating energy will change the operation methods for transmission and distribution systems significantly. Therefore the Cigre Working Group C6.08 inside the Study Committee C6 has dealt with the "Integration of Large Share of Fluctuating Generation" into existing electrical energy transmission systems. Experts from Belgium, Canada, Finland, France, Germany, Ireland, Italy, Japan, Netherlands, U.K., and USA worked together and described solutions for this challenge in their countries. This report is focused on the following topics:

- Power Flow Control and contingency management in networks
- frequency control
- grid stability
- reactive power and voltage control
- influence on the conventional generation
- regulation and support strategies

For **Power Flow and Power Flow Control** problems are addressed which describe the fact, that large unexpected fluctuations in wind power can cause additional loop flows through the transmission grid. When a large power deviation has to be balanced by other sources, these sources are not necessarily located near the wind park. For the flows through the parallel transmission paths, the direction of this power deviation may reverse, making it very difficult to reliably operate them. Partly in order to have a level of control on their power system, some system operators are actually installing power flow controlling devices in the transmission system. Currently there is no clear legislation which deals with reimbursing costs related to this issue. The preferred solution to this problem is to build additional high voltage transmission systems, but this is a very difficult and time-consuming process.

Congestions in networks caused by wind power are addressed from the market side of view using Intra-zonal and Cross-border congestion management methods as well as from the technical side of view using FACTS devices. Also some statistical aspects of the wind induced power flow are taken into account. It is shown, that the installed wind power in particular grid areas already achieved magnitudes which entails problems in grid control and grid operation management in strong wind periods, caused by large power fluctuations. Here, the active contribution of wind farms in grid operational management is required.

The increasing contribution of wind energy requires advanced solutions and new technical characteristics of wind power plants corresponding to the requirements of traditional power plants to keep the existing high level of power quality and safety of supply. Today it is already foreseeable that these demands must be reacted on with both **technical and regulative measures**. Large wind farms will therefore be centrally controlled in order to coordinate and adjust the operation of many individual wind turbines.

For **the frequency control area** the individual characteristics for **primary, secondary and tertiary control** for different countries are presented. The effect of wind generation on inertial response is analysed on the Island of Ireland where the power injection from wind power plants is already relatively high compared to the total load. Possibilities of producing primary control power from wind farms are presented together with investigations concerning the influence of wind energy to the secondary control behaviour in the Canadian Manitoba Hydro System, the system of Ireland and in Japan.

Also the **Influence of wind generation on reserve requirements** is presented. A methodology is described to assess the impact of wind power on tertiary control requirements.

The additional need for tertiary reserves thereby is usually estimated through the comparison of the forecast errors of load and so-called "net load" which is equal to the load minus wind generation. Examples are given for the Minnesota system, the U.K. System, the Spanish and German system and the Nordic countries of Europe. As a result it is shown that the impact of wind power on the tertiary reserve and margins can not be neglected, since significant hourly fluctuations of wind power and forecast errors have to be managed. It is shown that the amount of required additional reserves must be assessed on a case by case basis using country specific statistical data. The results of such studies are dependent on the considered country due to the set of specific parameters to be taken into account.

For the **Long-term voltage stability** simulation results from the South Australian power transmission system are presented. It has been shown, that when replacing large synchronous generators connected to transmission level by small generators integrated into subtransmission or even distribution systems or far from load centre, the amount of reactive power reserve in the network is considerably reduced. For this situation the study shows the important trends that the reactive power contribution of wind farms is highly dependent on the technology used, the connection point and voltage level as well as additional reactive power support (SVC, STATCOM) and that the reactive power reserve in the network is reduced by an increasing substitution of conventional power plant by wind generators and that there is a steady reduction of the long-term voltage stability limit resulting in a reduction of the maximum transfer along the interconnecting lines.

To counteract against the reduced reactive power reserve caused by wind power several measures can be taken as including additional reactive power sources, like switchable capacitor banks, SVCs, STATCOMs, synchronous condensers, etc. or increasing the number of "must run" units for conventional power plants or location of large wind plants with dynamic reactive power control on the transmission system.

For the **Short-term voltage stability** simulations were conducted in the Australian network. There is a trend towards lower import limits with increasing amount of wind generation in South Australia, although the short-term voltage stability limit always remains above the long-term limit. It can thus be concluded, that the short-term voltage stability is not as critical as the long-term limits. The results especially highlight the relevance of low voltage ride-through capability of all wind farms under all voltage variations that can occur, if the system is operated close to voltage stability limits. Low voltage ride-through capability has now been recognized as an important requirement in most grid codes around the world.

For the Australian National Grid Operator the Effect of Wind Power on **Transient Stability and Low Voltage Ride-Through Capability** for different types of wind power generators was simulated. Different types of wind plant generators like Directly Grid-Coupled Induction Generator, Doubly-Fed Induction Generator, Full-Converter Synchronous/Asynchronous Generator, Directly Coupled Synchronous Generator and Hydro-Dynamically Controlled Gearbox were taken into account. The different influences of these generator types are shown and methods to increase transient stability are proposed.

For the **Reactive Power Control and Voltage Control Capability** Grid Code Requirements for wind power plants for Ireland and U.K. are presented.

The **Influence of Wind Energy to Conventional Generation Plants** is described as a case study of the Belgian System. Especially the reduction of green house gas emissions that can be obtained by using wind energy converting systems is described. As a conclusion, it was found that the green house gas emissions reduction in Belgium is in the range of 350–450 kg CO_2 per MWh of power generated by the wind energy converting systems. It is mentioned that the overall emissions of the Belgian system are about 300 kg/MWh for the complete system and almost 500 kg/MWh for the dispatchable fossil-fuel fired part of the generation mix.

Managing wind forecast errors is investigated for the systems of Ireland and Germany. **Necessary investment in conventional power plants** is discussed. The value of the so called capacity credit attributed to wind energy is presented for the French and the German system. As a result it can be stated that the capacity credit is strongly dependent on the climatic and geographic conditions applicable for a considered region or country. Also it can be stated that the capacity credit will decrease with increasing wind penetration rate. Based on measurements from Germany it can be seen that for whole Germany there are about 700 hours per year where there is literally no wind. This is the reason why a capacity credit of only 5 % has been retained. Wind power in France has a capacity credit of 30 % for an installed capacity in the range of 5 GW. The capacity credit would decrease to 20 % if 15 to 20 GW were connected with the same geographical dispersion as today.

In the last contribution the different **regulatory and support schemes in various systems and countries for wind powered generating** resources worldwide are presented. For this reason a Questionnaire was prepared and circulated among various TSOs and experts, seeking information about technical and regulatory issues related to wind generation. Feedback was given by the following countries: Australia, Canada, Denmark, France, Germany, Ireland, Italy, New Zealand, Spain and U.S. The results are given in a comprehensive conclusion describing all the different national measures in detail.

CIGRE WORKING GROUP C6-08
INTEGRATION OF LARGE SHARE OF FLUCTUATING GENERATION

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The convenor likes to thank all active members of this WG for the fruitful discussions during the meetings and via e-mail as well as for preparing their contributions for this report. Special thanks go to the members which have taken responsibility for editing the different chapters, without whose effort and assistance the task for the convenor and as well as for the secretary would have been extremely difficult.

Abbreviations

The following abbreviations have been used in this Technical Brochure:

3PF	**Three-phase Fault**
ACE	**Area Control Error**
AGC	**Automatic Generation Control**
ART	**Average Regulated Tariff**
ATC	**Available Transfer Capacity**
AVR	**Automatic Voltage Regulator**
CCF	**Capacity Conversion Factor**
CCGT	**Combined Cycle Gas Turbines**
CCT	**Critical fault Clearing Time**
CfD	**Contract for Differences**
CHP	**Combined Heat and Power**
CM	**Congestion Management**
CPI	**Consumer Price Index**
CREZ	**Competitive Renewable Energy Zones**
DFIG	**Doubly-Fed Induction Generator**
DG	**Distributed Generation**
DNO	**Distribution Network Operator**
DNSP	**Distribution Network Service Provider**
DTS	**Dispatch Training Simulator**
ERZ	**Energy Resources Zones**
ETSO	**European Transmission System Operators**
EU	**European Union**
EuroPEX	**European Association of Power Exchanges**
EWEA	**European Wind Energy Association**
FCAS	**Frequency Control Ancillary Services**
FERC	**Federal Energy Regulatory Commission**
FiT	**Feed-in Tariff**
FRT	**Fault Ride-Through**
FRTC	**Fault Ride Through Capability**
FTR	**Financial Transmission Rights**
GC	**Green Certificate**
GCO	**Green Certificate Obligation**
GDP	**Gross Domestic Product**
GEC	**Gross Electricity Consumption**
GHG	**Green-House Gas**
GO	**Guarantee of Origin**
HVDC	**High-voltage Direct-Current**
IOU	**Investor-Owned Utility**
IPP	**Independent Power Producer**
LFC	**Load Frequency Control**
LMP	**Locational Marginal Pricing**
LOLE	**Loss Of Load Expectation**
LOLP	**Loss Of Load Probability**
LSE	**Load Serving Entity**

LVRT	**Low Voltage Ride-Through**
MEC	**Maximum Export Capacity**
MS	**Member State**
NERC	**North American Electric Reliability Corporation**
O&M	**Operation and Maintenance**
OLTC	**On-Load Tap Changer**
OTC	**Over the Counter**
PST	**Shifting Transformers**
REC	**Renewable Energy Certificates**
REP	**Retail Electricity Producers**
RES	**Renewable Energy Sources**
RFP	**Requests for Proposals**
RO	**Renewable Obligation**
RoCoF	**Rate of Change of Frequency**
RPI	**Retail Price Index**
RPS	**Renewable Portfolio Standard**
SCADA	**Supervising Control and Data Acquisition**
SCC	**Socio-economic Cost of Congestion**
SCR	**Short-Circuit Ratio**
SO	**System Operator**
SSSC	**Static Synchronous Series Compensator**
STATCOM	**Static Compensator**
SVC	**Static VAr Compensator**
TCSC	**Thyristor Controlled Series Capacitor**
TNSP	**Transmission System Service Provider**
TNSP	**Transmission Network Service Provider**
TSO	**Transmission System Operator**
TTC	**Total Transfer Capacity**
UCTE	**Union for the Co-ordination of Transmission of Electricity**
UPFC	**Unified Power Flow Controller**
VRS	**Voltage Regulation System**
WACC	**Weighted Average Cost of Capital**
WECS	**Wind Energy Conversion System**
WFCM	**Wind Farm Cluster Management**
WPS	**Wind Power Station**
WT	**Wind Turbine**
ZDE	**Zone de Développement Eolien**

CONTENTS

1 Introduction

The power industry is facing substantial changes all over the world. This phase is marked by the foreseeable scarcity of fossil fuels and aggravated by the dramatic increase in energy demand in emerging countries, particularly China and India. As a result, we have seen a dramatic price increase for fuels during the last years. Recently it has once again become quite apparent just how much industrial countries depend on energy import and energy prices. Energy supply has been increasingly used as a means of applying pressure to assert certain economic or political interests. Furthermore, in view of the rapid rate of climate change, there is an urgent need for prompt reduction of energy produced from fossil fuels.

Industrial countries therefore give top priority to safeguarding a reliable, sustainable, environment-friendly and at the same time, low-cost energy supply. This includes a sensible energy mix and improvement in energy efficiency in generation, transmission and consumption. In particular, greater priority will be given to the renewable domestic energy sources, such as the sun, wind, water, biomass, geothermal energy systems etc.

At the beginning of the development, the electric energy produced from the first small wind turbines was very expensive and needed high subsidies. Theses subsidies, mainly given in terms of fixed feed-in tariffs, have turned out to be the main driver for the deployment of this technology. This successful German model has been adopted by a large number of countries. Today single units with rated power up to 5 MW are on the market. Together with mass production, this has allowed a substantial reduction in energy costs from these units leading to reduced subsidies. Meantime the prices for fossil fuels literally exploded, especially for crude oil. The price for natural gas will follow with a certain delay but also the price for coal is expected to rise significantly. This will entail also a considerable increase in the price for electric energy produced from fossil fuels making the generation on the basis of renewable resources still more attractive. Of course also the prices for steel and other raw materials needed for the construction of wind power plants have increased considerably. Nevertheless it is generally agreed that the economic attractiveness of renewable energies will further improve, especially when compared with new entrant conventional generation based on fossil fuel.

The share of power generated from renewable energy sources (RES) worldwide has increased significantly during the last years and is expected to rise further with increasing gradients. Especially the contribution from wind energy showed the highest growth rates during the last years. By the end of 2007 nearly 94 GW of installed capacity from wind turbines have been reached worldwide, more than 57 GW of which are installed in Europe (22 GW in Germany). Nearly 20 GW have been installed during the last year (2007) and a total amount of 160 GW is expected to be reached by 2010. The stated aim of national and European energy policies is a considerable contribution from renewable energy sources. The European Commission's target for this contribution is 20 % by 2020. Their Strategic Energy Technology Plan shows a potential for wind power of 180 GW in 2020 and even 300 GW in 2030. For Germany with its already existing high amount of onshore wind turbines, the most probable growth is seen in wind energy at offshore locations and the repowering of existing onshore sites with the aim to reach 47 GW in total by 2020. Such high penetration of wind energy means that we will see more frequently situations where the energy produced from wind turbines is higher than the actual load in the grid, mainly during low-load periods. Locally this situation already occurs in certain regions, e.g. in Germany and Denmark.

A major challenge for a further increasing contribution from these renewable energy sources lies in their variable output directly following the fluctuating weather conditions. Although the tools for predicting generation capabilities from wind power have considerably improved,

the scheduling of these units remains difficult. Reported durations of unavailability of power produced in onshore wind power plants can reach up to some weeks during special weather conditions and are not locally restricted. Most RES (with the exception of reservoir hydro and biomass) have no inherent storage capabilities and thus the power generation directly follows the actual conditions (wind speed, water flow of rivers, solar radiation intensity). These depend on seasonal, meteorological or other conditions and are not controllable. Recent studies indicate that with a further deployment of RES, increasing system flexibility will be required to manage the task of system balancing.

Today, conventional power plants are needed in order to adapt the electricity generation at each moment to the existing load and to cover the periods of unavailability of wind and solar energy. Due to the actual structure of feed-in tariffs for energy from RES existing in most countries, these plants do not take part in the provision of power control, although technically this would be possible. As a consequence, the remaining conventional thermal power plants have to provide an increasing amount of control power and thus frequently operate at inefficient partial load or have to shut-down or restart. Beside increased losses, additional fuel consumption and emissions, this operation mode also causes increased wear and reduced lifetime of the plants. Together with a reduced load utilization period this will entail a considerable increase of specific costs for electric energy produced from these units. Existing conventional thermal generation plants generally offer only a limited potential of fast load following capability. Furthermore their capacity will continuously decline in the coming decades. The capacity of existing storage power plants (mainly pumped hydro) is far to be sufficient for future needs. Therefore large storage capacities will be needed together with system flexibility for balancing unavailability and fluctuations. Additional sources of system flexibility may be found in market oriented operation, more flexible generation, demand-side management, and energy storage.

Today's transmission and distribution grids have been planned and built for a top down load-flow having the large power stations as close as possible to the load centres. A huge potential of renewable energy sources is mainly available remote from load centres (large wind parks on- and off-shore). Furthermore, due to the liberalized electricity market, bulk energy transport is seen in the transmission grid. This leads to completely new load-flow situations and bottlenecks already occur today in the transmission grid at situations with high wind power. Contingency management may help in the short term but will remain only a compromise. In the long term, appropriate reinforcements of the grids are a must. Unfortunately building new lines is still an issue due to the strong opposition of the public, but is essential if the large volume of remote renewable energy is to be successfully integrated in the future. In this context it seems to be evident that also the construction of new lines as for all other equipment has to follow economic aspects.

In the past, a few singular small generation units based on renewable energy resources could more or less easily be added to the existing distribution system. Due to an increasing number of generation facilities embedded into the distribution grids, the increasing impacts are becoming obvious and even the load-flow may change according to the actual generation situation. Discrimination should be made between generation origin from fluctuating renewable resources (e.g. PV and wind, but also small run-of-river installations) and controllable generation, at least to some extent (e.g. biomass or biogas). In this context also the upcoming market for CHP-plants (combined heat and power) based on natural gas has to be regarded, although not being considered as renewable energy. Therefore a holistic, viable energy concept has to take into account both generation possibilities: small scale generation embedded in the distribution grid as well as bulk generation at remote sites and connected to the transmission grid.

In order to cope with this new situation, the transmission system operator (TSO), the local distribution system operators (DSO) and/or the national regulators have established technical requirements for the connection of distributed generation and large power stations (grid codes, distribution codes). Also international standards are on the way in order to harmonize these

requirements for a large number of countries. Wind turbine and wind plant technology has made tremendous strides in the last 10 years in terms of developing equipment and controls that are more in line with the requirements of the power system. These requirements are being reflected in increasingly stringent grid codes requiring such features as low voltage ride through, voltage and VAr control, governor action, and inertial response. While many of the issues of the past are associated with a lack of these features, they are becoming recognized as more standard capabilities for present and future equipment.

Before granting connection to the grid, the grid operator has to check several technical aspects:

- contingencies (even in remote parts of the system)
- contribution to short-circuit currents
- stability aspects (voltage stability, transient stability)
- draw back to the protection system
  - safe and selective tripping
  - fault ride through capabilities
  - behaviour under islanded conditions

In the future, distributed generation and bulk generation from RES will not only deliver energy but may/must contribute also to the ancillary services:

- voltage control: power electronic converters may contribute by feeding or absorbing reactive power corresponding to actual needs
- frequency control: due the large amount of fluctuating power from wind generators there is a need for additional control power
- contingency management: re-dispatching, including controllable distributed generation (e.g. CHP-plants) may be used for optimized grid operation

Together with generation dispatching also the possibilities of load management (demand-side management) can be used to adapt the load to some extend to the actual generation situation.

Most of these features are only possible by integrating also the distributed generation and the loads in a sophisticated management system taking advantage of the future possibilities of information and communication technologies.

When discussing fluctuating energy issues, it is a must to consider also the possibilities for energy storage. A new CIGRE WG C6.15 recently set up will deal especially with storage issues. Large scale storage is possible in pumped-hydro power stations but in the future also compressed-air energy storage will be seen. The production and storage of hydrogen could be a solution, although the low overall efficiency for the whole hydrogen chain, (generation, storage and combustion) of only 30 to 35 % would be a big hurdle. At the distribution level new battery systems might be used to cope with local power imbalances and bottlenecks, providing at the same time an improved power quality for sensitive customers.

With regard to hydrogen, future energy supply concepts therefore should not only concentrate on stationary applications but also take into account the energy need and the supply infrastructure for the transport sector. In this field, further progress in the battery development (Li-Ion) could lead to a revolution in car technology (plug-in hybrid). A fleet of such cars would represent a huge storage capacity which can also be used for grid issues. Connected to the grid most time of the day when being parked, those hybrid cars can be considered as a large virtual storage system capable of absorbing or delivering electric energy. The outstanding advantage of such batteries is their high cycle efficiency which is expected to reach 90 %. It appears also very important for the deployment of the plug-in technology that the main infrastructure is already existing, sufficient to accept a large number of such vehicles on the grid.

The present report is mainly focused on the following aspects:

- contingency management
- frequency control
- grid stability
- reactive power and voltage control
- influence on the conventional generation
- regulation and support strategies

CIGRE has initiated a number of working groups, which study various aspects of wind generation:

WG B4.39	"Integration of large scale wind power using HVDC and power electronics"
TF B5.08	"Protection and control for dispersed generation and impact on transmission"
WG C1.3	"Electricity Power System Planning with the Uncertainty of Wind Generation"
WG C4.601	"Modeling and Dynamic Behavior of Wind Generation as it Relates to Power System Control and Dynamic Performance", Final Report: January 2007
WG C6-01:	"Development of dispersed generation and consequences for power systems"
WG C6-04:	"Connection and Protection Practices for Dispersed Generation"
TF C6.04.01:	"Connection Criteria at the Distribution Network for Distributed Generation"
WG C6.05:	"Technical and Economic impact of DG on Transmission and Generation Systems"
WG C6.08:	"Integration of large share of fluctuating generation" (this report)
WG C6.15	"Electric Energy Storage Systems"

A new Joint Working Group JWG C1/C2/C6.18: "Coping with limits for very high penetrations of renewable energy" will continue to work on these issues. A first meeting was held during the CIGRE Session 2008.

Further investigations are still needed in order to study the simultaneity of wind availability over larger cross-national regions. At low market penetration, it has been possible up to now to export wind power to neighbouring regions/countries during excess situations or to import additional power when there is locally a lack of wind. It is of particular importance to know if this will hold true also for high area-wide market penetration of wind power plants.

When studying the impact of power produced from RES it is not sufficient to consider only wind energy but also solar energy; e.g. it has been shown, that there is less wind available during summer month whereas this could be compensated for by solar power plants which show their maximum output during this period. Also the future potential of biogas and biomass needs to be analyzed as it is discussed to activate these resources at low wind conditions.

Future work should also focus on the interaction of distributed (embedded) small-scale generation with bulk generation (large wind parks on- and off-shore, large solar-thermal power plants in the sun-belt as well as conventional generation). Although not only a domain for electricity, the future energy demand for heating issues has to be taken into account. In this context also the possible contribution from distributed generation in small-scale gas-fired CHP-plants (mainly seen for domestic heating issues) has to be considered as also their operation will be influenced by RES. With regard to heating and/or cooling issues, the possible potential of local thermal storage capacities has to be taken into account together with a future smart demand-side management. Also the emerging demand for electricity in the transport sector should be part of future considerations.

2 Power Flow and Congestion Management

2.1 General Situation in Europe

Contributors: P. Souto, J. Driesen, L. Meeus, K. Purchala, H. Holttinen, J. C. Smith

Wind power is, together with biomass, the fastest growing renewable energy technology in Europe. During the last decade, the fast development of both, the amount of installed wind power and the technological evolution of the turbines, have continuously exceeded the most ambitious targets. The target for total installed wind power in the 15 Member States of the European Union (EU-15) for the year 2000 was set at 4 GW in 1991 and revised to 8 GW in 1997. Finally, in 2000, the real value exceeded 13 GW. Also for the year 2010, the targets have already been modified upwards: from 40 GW (set in 1997) to 60 GW (set in 2000) and further to 75 GW (set in 2003). The actual installed wind power at the end of 2005 was 40 GW, meeting the original 2010 deadline 5 years in advance. Figure 2.1 shows the installed wind capacity in Europe at the end of 2007.

Fig. 2.1: Installed wind capacity in Europe. (source EWEA [2.1])

However, the integration of this increasing amount of wind power in the power system raises a number of issues. On the technical side, different grid requirements are applied to wind power in each country, restraining the industry in their standardizing impulse, thereby increasing the price for specialized turbines designed for a particular set of requirements. Also different criteria are applied when settling grid access in every country. On the market side, a variety of economic incentives are created to promote the development of wind power, restricting the setting of a European market for green energy.

Wind power is the typical example of a variable energy source. The fluctuating nature of generation causes it to have rather unique properties among the other, more traditional, energy sources [2.2].

Large penetration of wind energy can raise concerns in the following areas for the interconnected power system:

- Most wind generators, and in general most distributed generation sources, are not currently required to contribute to the frequency control and other ancillary services. This is mainly due to the time invariant feed-in tariffs. With large penetration of these uncontrolled energy sources, the effective frequency control action has to be performed by a smaller portion of the generators. Modern wind turbines with power electronic controls are capable of providing this function and will be increasingly required to do so in the future.

- Wind energy generation is often grouped, but this is not always near load centers. When large amounts of power have to be transported over long distances, congestion on existing grids can occur. This is for instance already the case in the UK where electric power is transported from the North of England and Scotland to the south. A similar problem exists with the German wind power which is mostly located in the North. This causes, due to Kirchhoff's law, large transit flows through the Benelux and France at the one hand and through Poland and Czech Republic on the other. These flows limit the use of the respective power systems for other purposes like market facilitation, and could even congest them, making dispatching necessary, possibly even across borders.

- Not all wind generators are able to deliver ancillary services (reactive power control, ride-through capability. . .) to the grid. Recently, several grid operators have put up guidelines for the connection to the power system, stating the necessary requirements which can be met by the turbines themselves, or with the addition of suitable equipment.

2.2 Behaviour of Wind Power on the Irish Power System

Contributors: Ivan Dudurych

The island of Ireland's Power System is comprised of the Republic of Ireland (RoI) Power System and the Northern Ireland's (NI) Power System that are under different jurisdictions. These two systems are lightly interconnected by dual circuit 275 kV AC lines and two 110 kV lines. The NI Power System is connected to Scotland by a 500 MW HVDC link. The combined maximum/minimum demand of the two systems is approx. 6,800/2,500 MW. Tripping of the largest generator (420MW) can result in a frequency fall of 0.5 Hz and more even with primary fast acting operating reserve of 75% of the maximum infeed. The relatively small size of the system also dictates wider frequency variations under normal conditions (±0.1 Hz 90% of the time). Under-frequency defence measures can be initiated that include pumped storage response (290 MW), gas-turbine peaking, contracted customer disconnection and load shedding. Generation plant is mostly thermal, with some 3% hydro, 4% hydro pumped storage and 6% wind. The RoI's transmission system is operated by the TSO EirGrid.

The rapid increasing of wind power generation in the Irish Power Systems over the last few years imposes further challenges for Power System Operators and EirGrid in particular, mainly due to the fluctuating character of wind power production and forecasting uncertainty. The installed wind capacity on the EirGrid System has grown from 68 MW in 1999 to approximately 800 MW in 2007. This represents almost 12% of the installed generation capacity. Such growth has been due to a number of reasons including government commitment to the renewable sector arising from the Kyoto agreement and EU directives, the proven maturity and commercial availability of wind turbines [2.8], and greater understanding of the impact of wind generation on power system operation [2.9]. Up to October 2004, some 80% of all installed capacity was connected to the distribution system with the balance to the transmission system. Since then with the emergence of larger WPSs, the trend is towards direct connection to the transmission system. It is estimated that by January 2008, 50% of WPSs will be connected to the transmission system.

As shown in Fig. 2.2, the majority of Ireland's WPSs (85% of the total installed capacity) are located in the West of Ireland, where wind resources are most widely available. Consequently the 'smoothing effect' due to the geographical spread of WPSs is minimal.

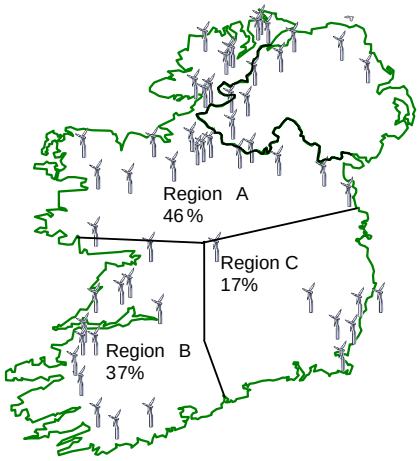

Fig. 2.2: Schematic layout of WPS location in Ireland

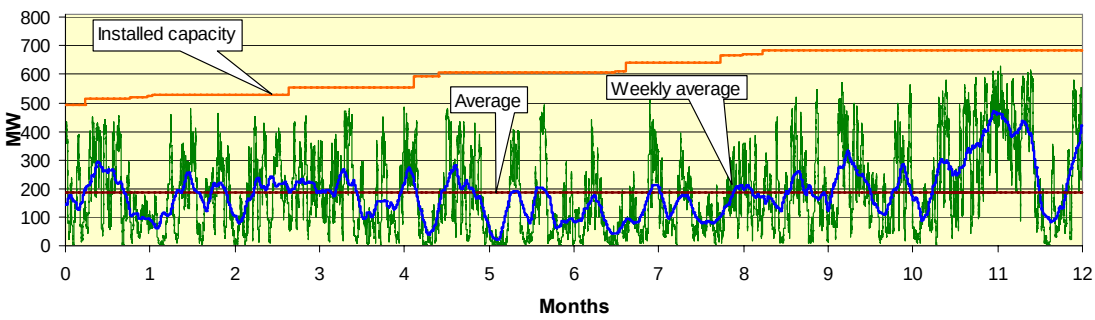

Figure 2.3: Total wind power generation from all Republic of Ireland WPSs for year 2006

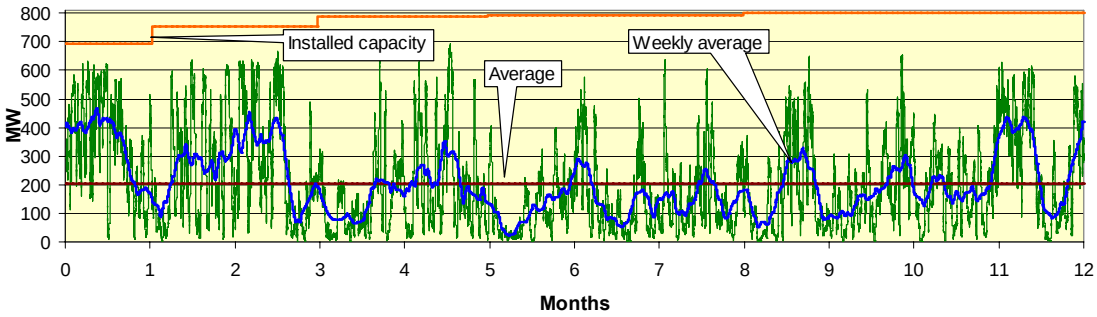

Fig. 2.4: Total wind power generation from all Republic of Ireland WPSs for year 2007

The actual wind generation output can vary from 0.5% to 96% of the total installed capacity of wind generation (see Fig. 2.3 and 2.4), while 95% of the time it generates less then 80% of its installed capacity. From Fig. 2.5 it is seen that average instant wind power generation is greater than 50% of its installed capacity for 95 days in a year. The rest of the time, it is less than 50%. The yearly median wind power output (capacity factor) varies from 27% to 34% and averages 31% (Fig.2.6).

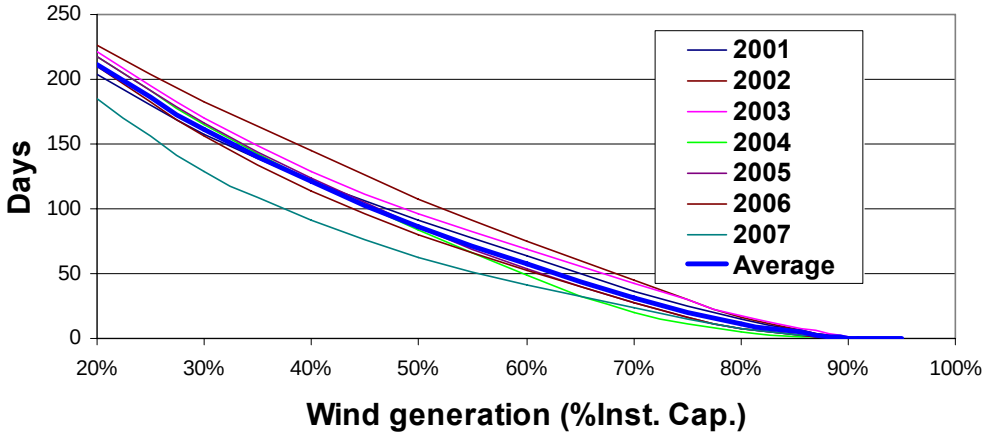

Fig. 2.5: Wind power output distribution in years 2001-2007

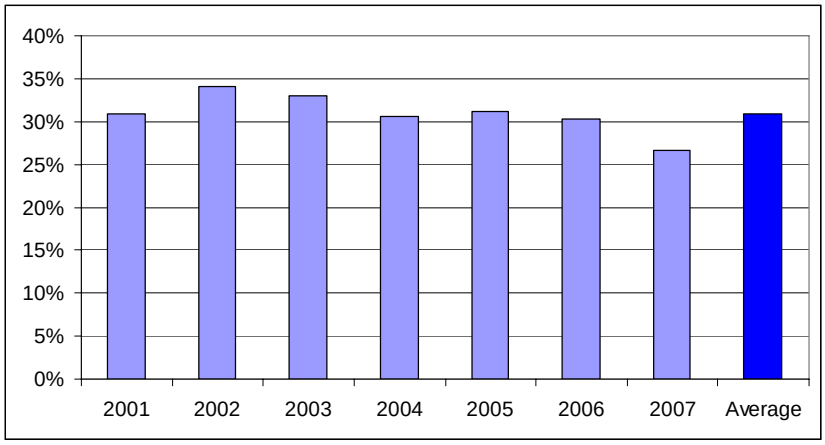

Fig. 2.6. Wind generation capacity factor in years 2001-2007

2.3 Statistical aspects of the power flow from wind turbines in Germany

Contributors: Kurt Rohrig

2.3.1 Availability of Power Production from Wind

The availability of the power supply generated from wind energy varies fundamentally from that generated conventionally from fossil fuels. For integration into the existing electricity supply system, two factors are particularly important: the fed in power fluctuates dependent on availability and is characterised by decentralised generation from a great number of plants. The continuous power measurements carried out by the "German 250 MW Wind Programme", on WTs connected to the remote data acquisition network, offer a unique data source for analysis of the total electricity fed in from wind plants in Germany.

Today, the statistical analysis of wind power generation is an essential element of grid and system control, as the installed wind power has already reached the minimal load in some distribution grids and therefore the load was temporarily covered from wind to 100%. By continuing the annual installation rates in the coming years, the installed wind power will also reach this magnitude in other regions of Germany. In this chapter, the time series of the cumulative power, measured in 15-minute intervals, of an individual plant (225 kW), a group of wind farms (72.7 MW) and all WTs in Germany (approx. 18 GW) are analysed and compared. The properties of the availability-dependent fluctuating wind power are first characterised by example time series, power variations and power duration curves. Particular attention is paid to the smoothing effect of the power generation, which results from decentralised generation by groups of WTs -spread over a wide area.

2.3.2 Smoothing of the Power Generation in Widely-Spread WT Groups

Apart from large-scale weather conditions e.g. the movement of low pressure areas, the power output of individual WTs is also determined by atmospheric turbulence and local conditions as well as individual plant behaviour, leading to strong power output fluctuations. In large areas with WTs, short-term and local wind fluctuations are largely balanced out and the temporal development of the power output is determined by the weather situation. Figure 2.7 shows the temporal characteristics of the feed-in, scaled to the corresponding rated power, of an individual plant (above), a group of wind farms (middle) and the overall wind power for Germany (below) over a time period of 10 days. The smoothing effect caused by the spread of the WTs over a larger area and by the larger number of turbines can clearly be seen. The time series shows large power output fluctuations for the single turbine. In the wind farm group, a slower increase and decrease of power output can be noted for the same period. In the cumulative time series of all wind energy plants in Germany, the power fluctuations are much weaker and the gradients in power output as well as the peak values are much reduced.

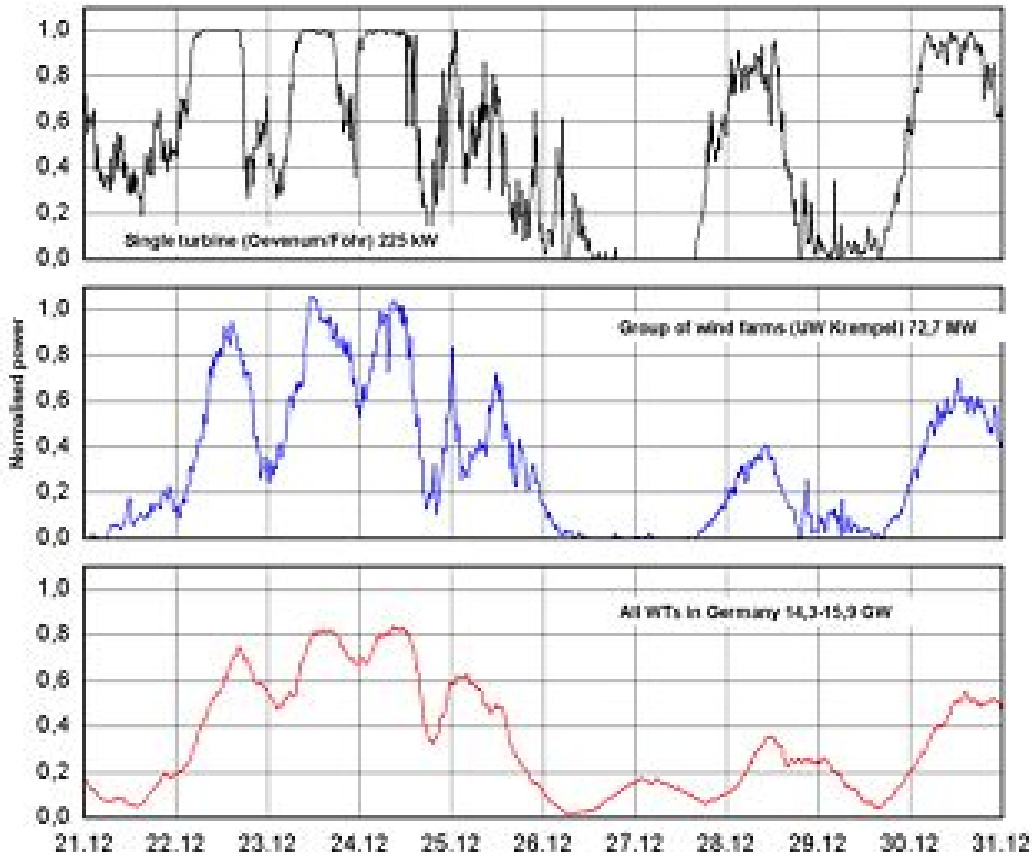

Fig. 2.7: Temporal characteristics of wind power generation

2.3.3 Changes in the Power Feed-in from Wind Energy Plants

The spatial distribution of WT's in Germany also causes a smoothing of power gradients. Single wind farms may cause large power level changes within minutes (storm cut-out), against this, larger areas have power gradient of 10 % to 15 % within 15 minutes. The figures 2.8 and 2.9 show the frequency of power level changes within 15 minutes of a single wind farm (72 MW) and of the whole wind power generation in Germany (22.000 MW) of one year. The x-axis shows the power generation level at a certain time and the y-axis the level 15 minutes afterwards. It can be shown, that the single wind farm causes power gradients of 60 % within 15 minutes. The aggregated power curve of Germany causes gradients of 15 %.

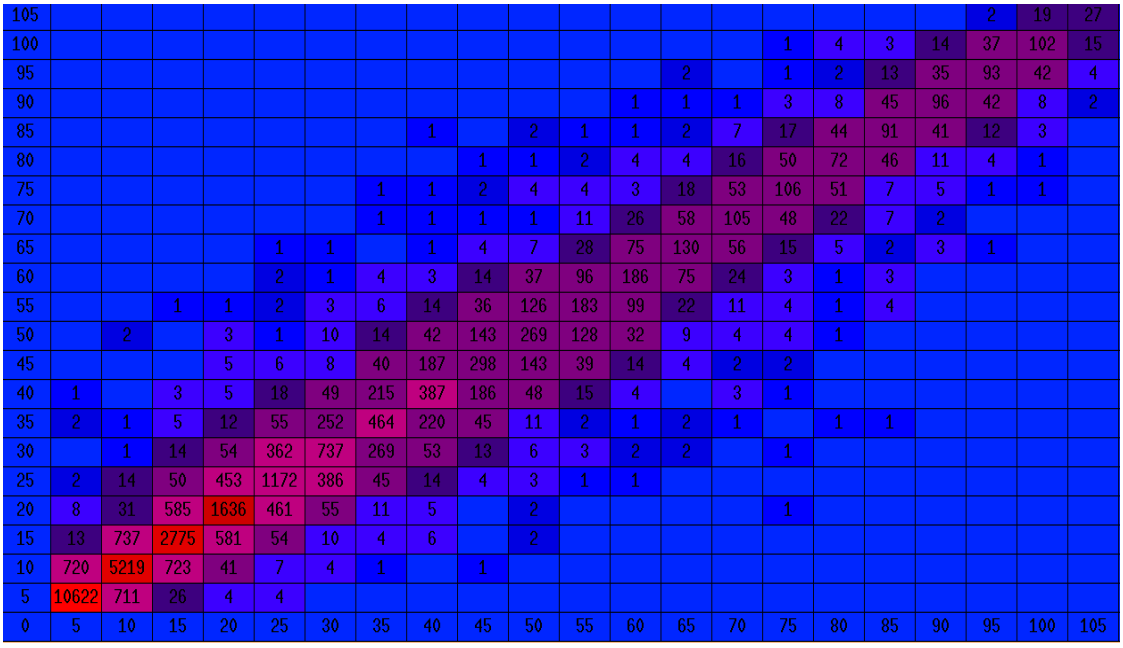

Fig. 2.8: Power fluctuations in 15 min time resolution wind farm (72 MW)

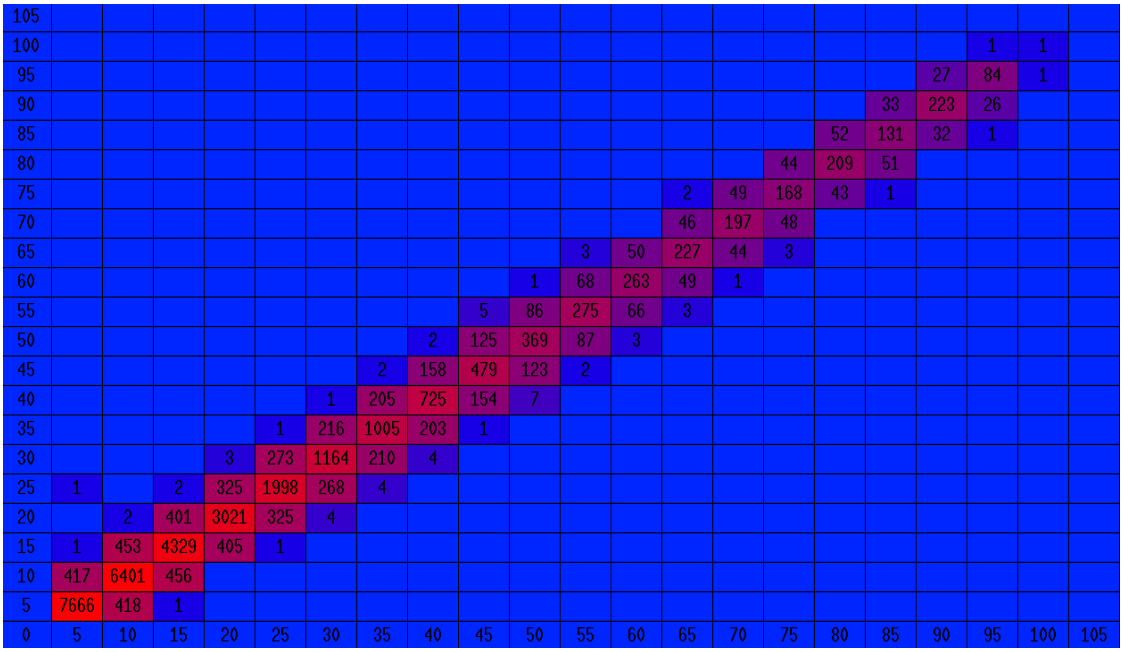

Fig. 2.9: Power fluctuations in 15 min time resolution Germany (22 GW)

2.3.4 Characterization of power fluctuations

A further important measure is the probability density function (PDF) of wind power fluctuations. The analysis is based on measured wind power of 60 wind farms which are distributed over the whole of Germany with capacities in the range from 3 MW to 140 MW.

Mean values of active power will be denoted by P(n) for every hour n ($n \in N$). For this analysis, fluctuations of power output are characterized by the following variables:

Wind power output variation "dP", determined by (1):

$$dP(n,k) = P(n) - P(n-k) \qquad (1)$$

The dependence of PDF of wind power gradients on the installed power for an increasing aggregation level is shown in fig. 2.10. In graph (a) the smoothing effect can be seen, i.e. the more installed capacity is aggregated, the narrower the PDF becomes. The top view in picture (b) makes the effect even clearer. Here it can be seen that the smoothing effect is most evident at low capacities.

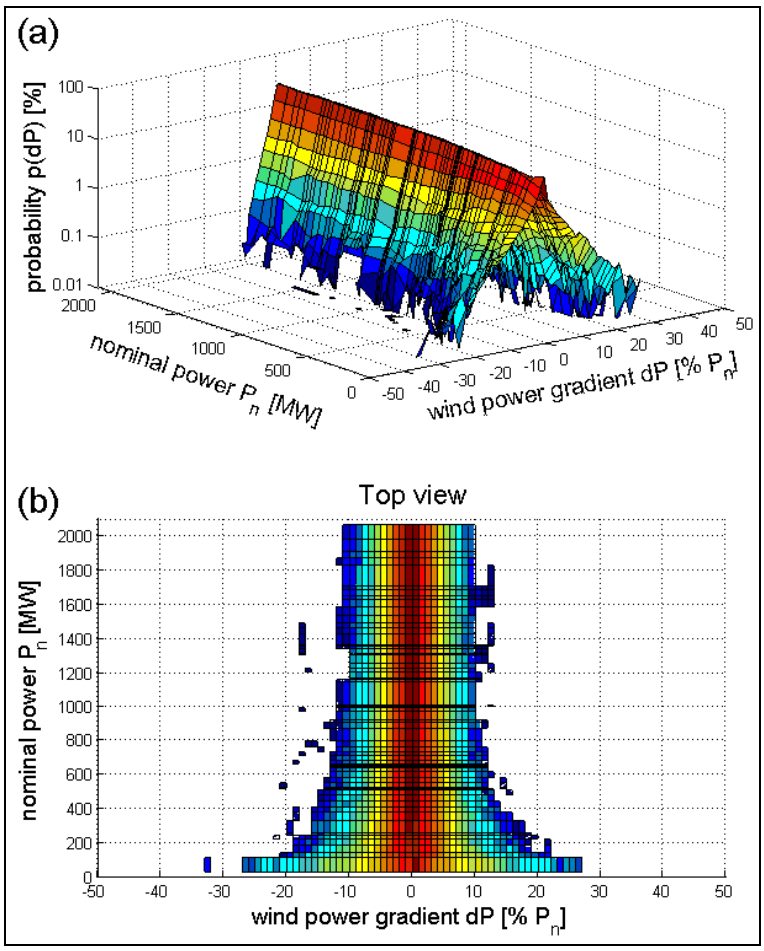

Fig. 2.10: PDF of wind power gradients as functions of the size of the inspected ensemble, given by the aggregated installed capacity.

2.3.5 Power Duration

Power duration curves show the numbers of hours per year during which the power level of the feed-in from wind energy plants lies above a certain minimum power. Figure 2.11 shows the power duration curves of all wind energy plants in the German grid in comparison to the duration curve of the electrical demand. The course of the curves, which correspond in their integral to the annual energy production/consumption, depends on the level of available wind energy and particularly on the distribution over the area of the installed WT.

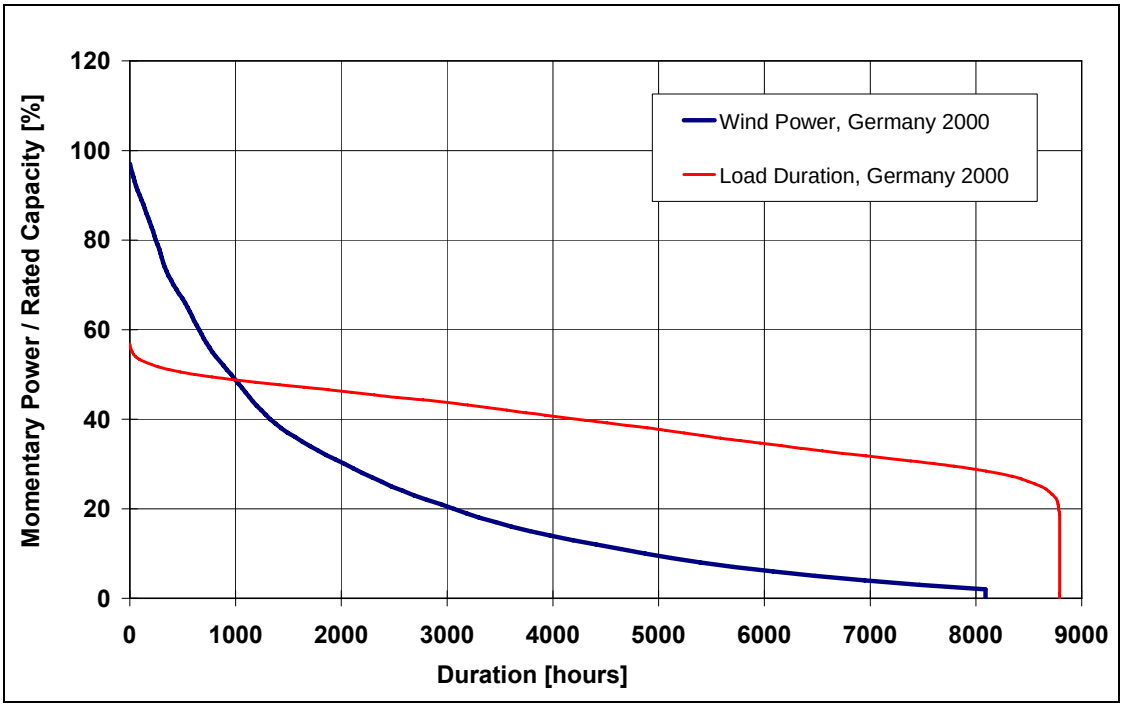

Fig. 2.11: Power duration curve of total wind power feed-in, Germany 2000

2.3.6 Power Flow

The smoothing effect of gradient and power fluctuations causes power transmissions over large distances. In Germany, the horizontal exchange of wind power between the control zones effects more and more large power flows between Western and Eastern Germany. These power flows are the reason for grid congestions and extreme situations in grid operation. The figure 2.12 shows the frequency of contemporaneous wind power levels in the Western area (E.ON, RWE, EnBW) compared to the Eastern area (VE-T).

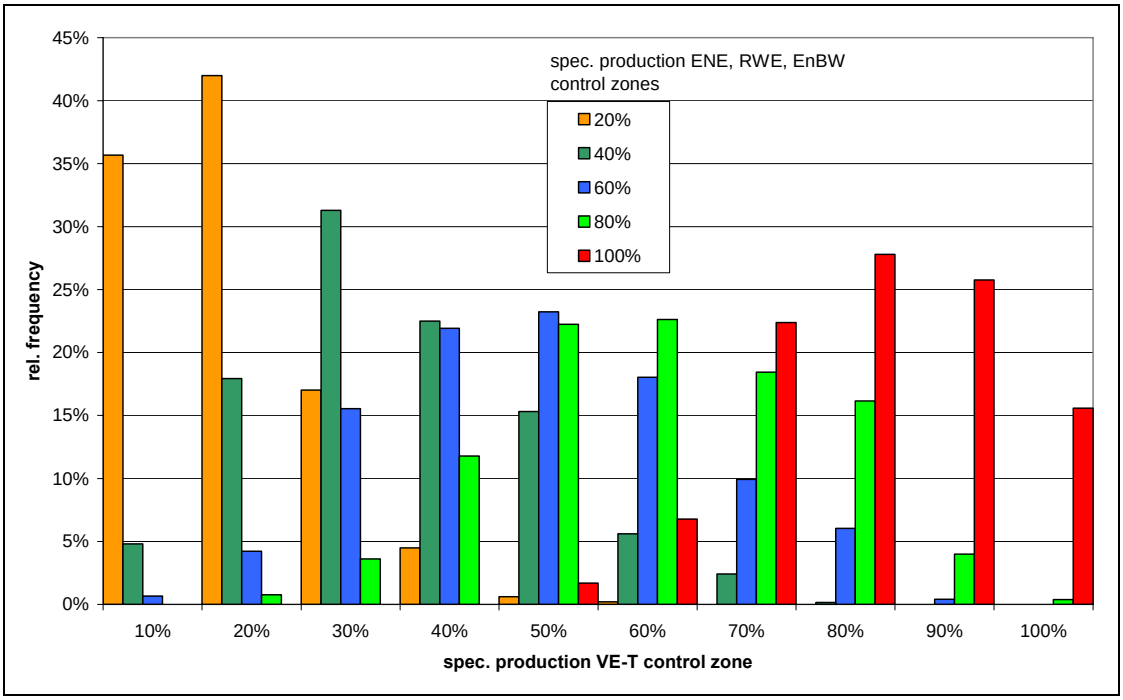

Fig. 2.12: Contemporaneous wind power generation levels in the German control zones

It can be seen, that in 5% of the year (430 hours) the difference of wind power generation levels between Eastern and Western Germany was about 20% of the installed capacity. These differences cause large power flows between the control zones.

2.3.7 Conclusion

In Germany, the installed wind power in particular grid areas (and control areas) already achieved magnitudes where problems occur in grid control and grid operation management in strong wind periods, caused by large power fluctuations. Situations have been listed, in which the total grid load of grid areas within the control area of Vattenfall Europe Transmission was covered by wind energy, and grid stability could only be maintained through interaction with other control areas. This aspect is particularly significant in conjunction with the erection of larger offshore wind farms, which supply power in the range of several hundred MW over one connection point. Here, the active contribution of wind farms in grid operational management is required.

The increasing contribution of wind energy requires advanced solutions and new technical characteristics of wind generation units corresponding to the requirements of traditional power plants to keep the existing high level of power quality and safety of supply. It is today already foreseeable that these demands must be reacted on with both technical and regulatory measures. Large (offshore) wind farms will therefore be centrally controlled in order to coordinate and adjust the operation of many individual wind turbines.

2.4 Congestions caused by the output from wind power

Contributors: P. Souto, J. Driesen, L. Meeus, K. Purchala, H. Holttinen, J. C. Smith

2.4.1 Influence of wind fluctuations on the grid

The varying output power and the limited predictability of these fluctuations causes the following additional concerns to the power system:

- Since the electric power system has limited, or virtually no storage, the power generated has to match the consumed power at any time, including grid losses. Therefore, other power plants have to keep a certain reserve power in order to balance generation and load. This leads to a reduced efficiency of the classical power plants. Another option is curtailment of the wind energy produced, resulting in a loss of profit for the owners of the wind systems, and a not optimal use of available wind energy. From existing experience and several wind integration studies it has been shown that operating the power system with a substantial penetration rate (5-20%) will result in more reserve power utilization. However, the impact of increased reserve requirements and increased use of reserve power remains small or moderate up to penetration levels of 10-20 % of yearly consumption by wind energy [2.4].

- Large unexpected fluctuations in wind power can cause additional loop flows through the European transmission grid. When a large power deviation has to be balanced by other sources, these sources are not necessarily located near the wind park. In case of Germany, a sudden reduction or increase in wind power will be balanced with hydro power from Bavaria. For the flows through the parallel transmission paths, which in the case of Germany is formed by the Benelux and the Poland and Czech Republic combined power system, the direction of this power deviation may reverse, making it very difficult to reliably operate them. Partly in order to have a level of control on their power system, the Belgian system operator, ELIA, is currently installing power flow controlling devices in the transmission system. This is an investment in the transmission system, due to wind energy, causing problems across the borders. Currently there is no clear European legislation which deals with reimbursing costs related to this issue. The preferred solution to this problem, as outlined in the DENA study, is to build additional north-south high voltage transmission inside Germany. This is a very difficult and time-consuming process, but as pointed out previously, is absolutely essential for the successful integration of the large amount of renewable energy planned for the future.

The unconventional nature of the wind as a generation source of the power system leads to a different market approach. Wind is to some extent unpredictable and unstorable. Introducing such an irregular parameter in the well established electricity market brings new problems and challenges. Changes in market design and operation recognizing the different characteristics of variable renewable resources will need to be considered.

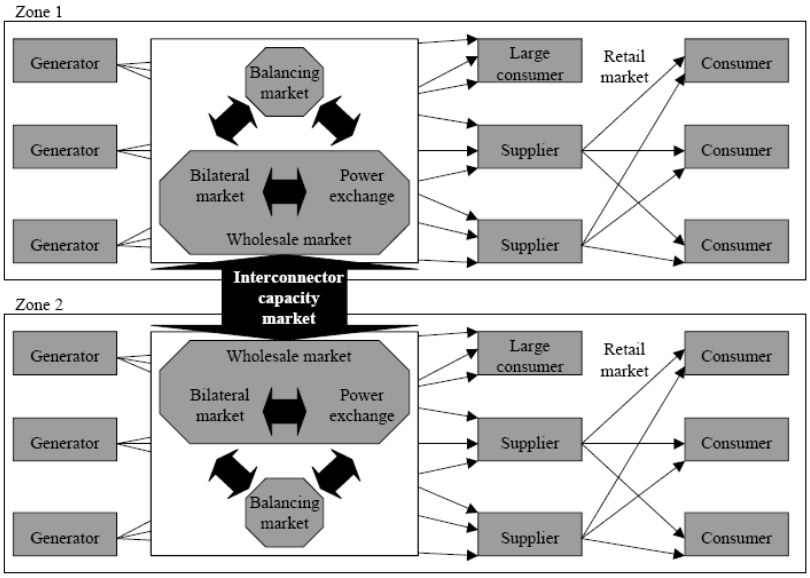

Fig. 1.13: Internal Energy Market structure [2.3]

2.4.2 Wholesale market

The wholesale market covers the trading of electrical energy between producers and consumers. Distinction is made between bilateral markets and power exchanges. Most wholesale volume in the electricity market is traded bilaterally by long-term and forward contracts, based on the expected generation and consumption portfolios. Wind power can be traded in long-term contracts only if the buyer can handle the balance settlement. Wind forecasting today shows that wind power predictions begin to be acceptable for market decisions one to two days in advance. Within one hour, the wind speeds can be predicted very accurately.

When dealing with real-time approaches, the conditions for generators and consumers may change due to unexpected events, machine outages or new business opportunities. To cover the difference between long-term contracted and real-time generation and consumption, there is need for additional intra-day trade in spot markets.

The spot market is in many EU Member States organized via power exchanges, i.e. trading platforms, operating day-ahead and facilitating anonymous trade in hourly or multi-hourly contracts. Thanks to these platforms, power traders do not need to search for an adequate partner for bilateral trading in a short timeframe, which is a costly operation and forces to reveal information of their actual market position. The power exchange matches the bids of generation and load to define a price on an hourly basis, ensuring that the total contracted power generation equals the total contracted demand. Even though only a small fraction of total trade goes via power exchanges, their public hourly price index may be seen as a reference for the contracts negotiated in other markets such as forward markets [2.4]. This type of market is where wind power can play its part more efficiently, with hourly contracts. One of the main disadvantages of wind power in spot markets is the imbalance payments. Also the different gate-closure time between countries can arise difficulties in the standardization of wind forecast methods and information exchange.

2.4.2.1 Balancing market

In the balancing market, balancing power is traded. The TSO purchases balancing power and procures it to ensure that the equilibrium between generation and consumption is satisfied at all instances of time. Wind power plays a main role in balancing in two different ways. The unpredictability of wind forces more activity in the balancing market, but experience proves that big wind farms can act as balancing parts, regulating their output according to control parameters, as shown in Figure 2.14 .

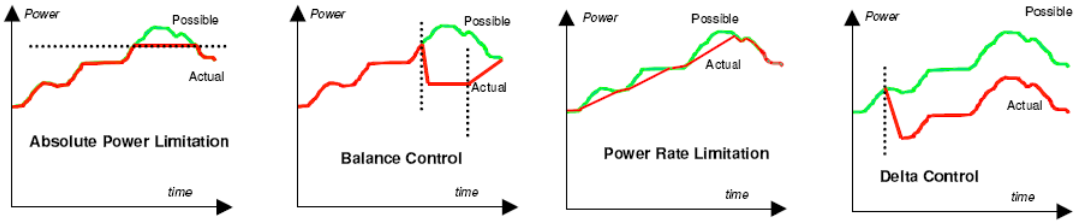

Fig. 2.14: Outline of the active main control functions.

Apart from the wholesale and balancing markets, an interconnector capacity market exists. This market finds its origin in the technical limits of the European high voltage transmission grid, which was initially only designed to allow assistance between control zones in case of emergencies. Liberalization of electricity markets lead to an increased use of the cross-border interconnections, resulting in large power flows over the borders. As a consequence, the physical interconnections between different control zones are often heavily loaded or even congested. In order to allow a fair and equal access to the interconnections, an interconnector capacity market is introduced, where the limited transfer capacity is allocated based on some previously agreed upon procedure. It must be noted that the physical flows in the European power grid are determined by the load and generation pattern as a whole. Therefore the identification of transactions actually using capacity or causing congestion on a specific interconnector is not straightforward [2.6], [2.7].

2.5 Effects of the congestion on the market

Contributors: P. Souto, J. Driesen, L. Meeus, K. Purchala, H. Holttinen, J. C. Smith

2.5.1 What is congestion

Congestion is a situation where the demand for transmission capacity exceeds the transmission network capabilities, which might lead to a violation of network security limits, being thermal, voltage stability limits or a (N-1) contingency condition. Congestion, being a result of power flows, may occur at any location in the interconnected network. Hence, in a physical sense congestion is merely an indication of a presence of transmission constraint. However, often due to the chosen market organization and the way congestion is managed, some transmission constraints can be managed different than the others. Typically in Europe, there is a difference between management of congestion inside the control zones of the system operators, and congestion on cross-border interfaces. Consequently, there is a division between an internal and cross-border congestion.

1. Internal congestion (Intra-zonal)

Internal congestion is situated within a single System Operator's control area. When intra-zonal congestion costs are socialized, the congestion may not be visible to a large number of market players. Therefore the control of its intensity has to be monitored and regulation has to intervene in case a socially unacceptable drift is found. When intra-zonal congestion costs are addressed through nodal or zonal pricing, transmission grid users are made responsible for the transmission constraints they cause.

2. Cross-border congestion (Inter-zonal)

Cross-border congestion, also called seams issues, is congestion between System Operator's control areas. The biggest issue is that market organization, regulation and investment framework on both sides of the interconnection can be different, making the allocation of cross-border capacity and settlements of congestion costs more difficult.

2.5.2 Consequences of congestion

Congested transmission lines indicate that the demand for transmission capacity exceeds the availability. Therefore transmission constraints imply deviation from merit order of power plants to feed the demand, either internally in the control zone of the system operator or across the borders. This loss of wealth results from inability to use the most economical generation resources and is often referred to as the socio-economic cost of congestion (SCC). Relieving transmission constraints reduces the SCC leading to more efficient use of generation resources.

However, there is a theoretical optimal point of congestion where the costs of remedying offset the benefits. Hence it cannot be stated that all congestion is unacceptable and must be alleviated at all costs. Rather, the structural congestion that is always present causing structural issues in accessing cheap generation resources should be dealt with as it will most likely be beneficial. Short-term congestion occurring only occasionally is something else and the choice whether to alleviate it or accept it is quite complex, as the reasons behind do not have to follow from merit order. What is likely to be causing short-term congestion is i.e. maintenance of transmission/generation facilities "weakening" the transmission grid, off-merit order dispatch of generation units caused by strategic behaviour, and last but not least, transmission investment policies of the System Operators related to wind power.

2.5.3 Causes of congestion

There are a number of factors that could contribute to transmission congestion. The most obvious ones are the following:

- Market organization
- Electricity price differences
- Fuel availability
- Inadequate transmission capacity

Market organization can indeed be a source of congestion, especially when the established rules give no incentives for the efficient use of the grid. A *copper plate* network model, typical for markets with Power Exchanges, is a prominent example. In this model, network constraints are managed by the System Operator, and market players do not have to bother

about them. This can obviously lead to an inefficient use of the grid, or incorrect behaviour of market players trying to create congestion and make profit out of it. Moreover, the network model assumed as a basis of some aspects of market trading can also contribute to creation of congestion. Given the self dispatch freedom of the European market participants and resulting and unpredictable internal dispatch pattern, the zonal network model is to a great extent responsible for the loop flows on cross-border interconnections. Zonal network model, applied throughout Europe for defining rules for cross-border energy trade, approximates the nodal reality by substituting control areas with single nodes, implying that the actual nodal dispatch information within zones is unknown for the neighbouring System Operators. The ever changing demand entails the even changing generation dispatch. Moreover, in the presence of wind parks the generation dispatch becomes even more unpredictable. All these are the most significant factors contributing to the ever changing fluctuation of cross-border flows.

Electricity prices are a function of the available fuel. Some countries, due to their geographical location, rely on hydro power. Other countries have abundant lignite coal, gas resources or a friendly wind power policy, all of these factors determining their fuel mix. Political choices can also be a significant factor, as for instance it is the case for the use of nuclear power or subsidizing renewable energy. With no legal barriers to cross-border electricity trade, market players look for the cheapest source of electric energy available. Therefore it is very important to organize the international electricity trade in such a way, that nobody takes a free ride making use of peculiarities in policy.

Availability of fuel is closely linked to energy price differences, as fuel shortages naturally lead to price increases. Systems experiencing fuel problems tend to have very high prices, which in turn attracts foreign traders. Moreover, the local demand in a system with generation shortages cannot be met by domestic sources, requiring more import and potentially congesting interconnections.

Inadequate transmission capacity, especially in cases of cross-border congestion, can be an important cause of congestion, given the history of development of the interconnectors. The transmission expansion planning process must evolve to the point that economical solutions to transmission congestion can be identified and implemented in order to achieve the renewable energy targets.

2.5.3.1 Nodal vs. zonal market organization approaches

Physically, the electrical grid consists of nodes (busses or busbars) connected by lines and/or transformers. However, as a consequence of a chosen market organization, very often groups of nodes are aggregated into areas. Areas are parts of the grid considered as copper-plates, meaning that the internal transmission constraints are initially ignored, and corrected in the dispatch planning phase. Areas are interconnected by means of transmission lines called interconnections. The control zone of one System Operator can consist of more than one area. Each of these areas may have a different energy price (price area).

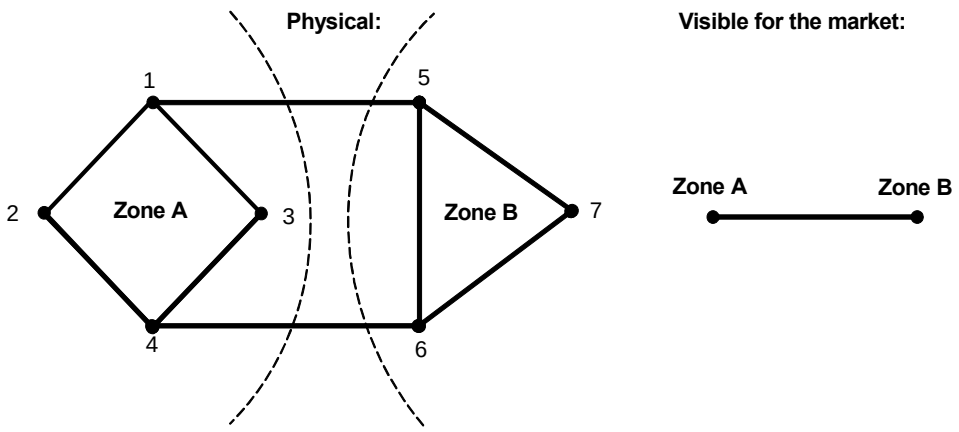

Fig. 2.15: From a nodal physical reality to a market oriented network representation

The difference between nodal and zonal network representations is illustrated in Figure 2.15 above, where the 7-node system is replaced by its 2-zone equivalent. The physical capacity of the lines interconnecting zones A and B, 1-5 and 4-6, is replaced by an aggregated commercial capacity A-B.

Since System Operators must ensure that the power flows always comply with security limits, some restrictions might be put on the cross-border flows. These limits are expressed in terms of commercially available cross-border transfer capacities, expressing the maximum power exchange between the zones concerned. However, the latter is not equal to the sum of the physical capacities, but is a result of existing or forecasted network conditions, strongly depending on nodal power injections and power flow patterns. It serves as an index, helping market players to estimate transfer capacities. Hence, if, for a given interconnection, there is more demand for cross-border capacity than commercially available, the interconnection is also treated as *congested*, meaning that no additional power can be transferred. This congestion is visible for market players as a limit on their cross-border transactions, though it is perfectly possible that the physical congestion has not yet occurred. At the same time, it is also not unlikely that even though the available commercial interconnection capacity is not fully allocated to market players, some lines, being internal or cross-border, become overloaded. This physical congestion is a problem of the System Operator and has to be dealt with by this entity. System Operators try to avoid such unforeseen congestion by carefully assessing the commercially available capacities and reliability margins.

Aggregated transfer capacities in a zonal network model can also be affected by the shifts of generation within a control zone, as these shifts influence the power flows on the interconnections. Depending on the network topology and the predictability of the internal dispatch pattern, the variations of nodal power injections can have a significant influence on the variation of cross-border flows.

2.5.3.2 Parallel/loop flows1 - the relation between physical flows and commercial exchanges

Physical flows on cross-border interconnections differing from commercial cross-border exchanges are a natural phenomenon in an AC interconnected power system. Physically, a power system consists of power plants and loads connected by a transmission grid consisting of lines, cables, substations and transformers. Due to laws of physics, power flows along the path of the least electric impedance and thus the power flow pattern depends only on the

[1] The term loop flow used in Congestion Management should not be confused with the same term used to depict circular power flows in the ring-shaped power systems.

location of sources, sinks and the grid topology. This means that any transaction between two nodes in a meshed network induces *some* power flow in *each* of its lines, except the peripheral antenna nodes (radially connected to the rest of the grid).
From the *commercial exchanges* point of view, the grid is considered as a market place that should allow maximum trading flexibility for different types of products. In a zonal network model these products are exchanged without any specification of origin or destination: they are purely commercial. However, the final real-time settlement of the trade will find a physical translation in generation schedules and load levels.
In congestion management, the term *parallel* or *loop flows* is usually used to refer to a situation where the actual physical flows differ from the expected ones due to transactions accepted in other parts of the interconnected power system. The more transactions and the more meshed the network, the higher the chance for mismatch between commercial exchanges and physical flows.

2.5.4 Congestion and wind power

Wind generation is a variable source of energy. However, the marginal cost of wind generation is zero. Hence, if there is wind, the design of the wind turbines and controls is typically to extract the maximum power from the available wind. However, in case wind is too low (or too high for that matter, and the turbines need to disconnect to protect from mechanical damage), power output of the wind turbines disappears.
As wind speeds are constantly fluctuating, it is necessary to carry additional reserves to manage the system balance. In other words, capacity credit of wind is limited, different sources quoting different numbers.
The above mentioned variability of output power, can be responsible for congestion. In fact, there are two possible issues:

- Congestion due to philosophy of transmission grid capacity sizing
- Congestion due to security margins assumed to account for wind power variability

2.5.4.1 Congestion due to sizing of the transmission grid capacity

It is generally recognized that the output of the wind turbine varies between full and zero power. In fact, the experience of the past years is that the average availability of wind generation is around 30%. This means that the occasions when wind turbine output is at full power are quite rare. Knowing this, Transmission System Operators take this fact into account, and for cost efficiency reasons sometimes are inclined to under-invest in the transmission grid. This choice originates strictly from the cost-benefit analysis performed by the TSO that need to reinforce the transmission grid to allow connection of a wind power plant. It must be recalled here that the TSOs are making their business on selling access to transmission grid (via the transmission). Hence each transmission investment must somehow pay off. TSOs perform the risk analysis to estimate the likelihood of the congestion caused by under sizing the grid connection, and if the results show that this risk and associated costs (i.e. costs to remunerate the wind park owner for his inability to transmit the output power) are lower than the costs of reinforcements, they could chose to accept this risk.
The same reasoning could be generalized to congestion leading to constraining the transaction of other grid users, i.e. conventional power plants. In many transmission systems, wind power and other renewable energy gets priority grid access. Hence it is imaginable that excess of wind power injected to the grid will constrain the ability of other units to inject power. This is

another source or risk for the TSOs, e.g. according to given grid access rules present in most of European control zones, TSOs must remunerate the parties who are curtailed (provided these parties have secured an adequate grid connection contract).

2.5.4.2 Congestion due to security margins assumed to account for wind power variability

Wind power fluctuations can lead to decreasing the ability of the transmission system operator to predict the power flows in its network. This means that during the operation and planning stage (i.e. week ahead, one day ahead), the output of wind generation is not 100% known. It is generally recognized that the wind power forecast is quite well 3-6 hours ahead, still adequate 1-2 days ahead, and quite poor in longer terms.

Estimation of available transfer capacity

As stated previously, cross-border electricity trade in Europe is realized based on the principle of zonal markets (price areas) linked with transfer capacities. In order to access a foreign market, traders need to secure cross-border capacity rights. This is done usually under a form of an auction. However, in order to sell the cross-border capacity to the market participants, the amount of capacity rights needs to be determined.

Estimation of cross-border transfer capacity is not a trivial task. On the one hand, there is a pressure from the market participants to make as much transfer capacity available as possible. On the other hand, TSOs cannot sell more capacity than they are able to guarantee, as the capacity rights are firm. One of the major difficulties are the strong interactions between the individual line power flows, following the fundamentals of electricity flows in meshed networks – the Kirchhoff laws. Currently ETSO defines the transfer capacities based on the Total Transfer Capacity (TTC), which indicates the maximal possible power transfer between two adjacent zones. In order to determine the TTC, the power exchanged between the two zones is gradually increased starting from the base case scenario, until a constraint is violated being thermal or (N-1) security limit. The values of TTC are directional. UCTE describes three methods that can be used to increase the cross-border power exchange needed for TTC calculations, the choice being left to subsidiarity:

- Proportional increase of power generation in one zone and a corresponding decrease in another. The generation can only be modified up to the technical limits of the unit involved.
- Proportional increase of power generation in one zone and a corresponding decrease in another without respecting the technical limits of generating units. This method is used in emergency cases where generation limits are unavailable or there are no other means of increasing the cross-border exchanges. It results in a theoretical TTC value, which does not take physical limits of generators into account.
- The cross-border power exchange is obtained by modifying the base case power generation according to a merit order. The maximal and minimal power of a generator is taken into account.

TTC forms a basis for the calculation of NTC and ATC, which are made available to the market. Especially the ATC value is important as this is what is made available for the market players for purchase.

What is the problem?

The major problem associated with ATC calculation, is that it is based on the prediction of power flows on a given border. TSOs need to predict the behavior of the market participants, and act upon this prediction by estimating what is the available room on the physical interconnections and how these will be utilized. All process must result in one single number for each hour of the following day, the number representing the transmission rights that are sold to the market. If however the behavior of grid users is different than expected, the offered ATC can become overestimated (or underestimated, though the latter at least does not entail direct operational risk) calling for security measures (re-dispatching, curtailment of transactions, etc – all in all costly measures for the TSO). Although there could be numerous reasons for the incorrect estimation of the power flows by the TSO, wind power with its inherent variability can be a significant cause. The availability of a day-ahead nodal injection wind plant output forecast will be an important tool to help manage this problem.

2.5.5 Measures taken to mitigate the congestion

There are many Congestion Management (CM) methods. Moreover, they can have different goals, as depending on the market organization different problems have to be solved. Some methods are applied on a day-ahead basis to prevent congestion, other have to be solved in real-time. Therefore the division of CM methods into subcategories is not evident.

A first line can be drawn between cross-border and intra-zonal congestion management methods, as these kinds of congestion are handled differently. Intra-zonal congestion is defined as a constraint within a system operator's control zone. If a transmission network treated as a copper plate, this means that the transmission constraints are the problem of the System Operator (i.e. it needs to pay for it). Cross-border congestion management on the other hand comes down to allocating a previously agreed upon amount of transfer capacity to market players wanting to trade between control areas. However, as explained previously, in real-time some of the assumptions might prove to be incorrect or some grid users may behave in a way that is inconsistent with their commitments. This in turn can cause real-time congestion that needs to be dealt with instantaneously. Methods to deal with such unforeseen situations constitute a third category of congestion management methods.

2.5.5.1 Intra-zonal congestion management

Intra-zonal congestion arises inside a control zone of a given System Operator. It is detected on a day-ahead basis, typically when unit commitment decisions of market players are communicated to the System Operator. Depending on the market organization, this congestion can be dealt with in different ways: it can be either socialized (transmission tariffs or as uplift on the pool price), or explicitly allocated to the ones that cause it using Locational Marginal Pricing (LMP).

In bilateral markets, often called Over the Counter (OTC) markets, the majority of energy is traded on a voluntary bilateral basis. Dispatch decision is entirely left to the market players and the only condition is that they need to communicate it to the System Operator, so that he can check whether the proposed dispatch is feasible as far as the grid is concerned. However, as the grid is assumed to be a copper-plate, there is a flat postage stamp transmission tariff (i.e. no regional differentiation). Congestion in this case has to be solved by the System Operator and the latter has to cover the incurred costs. These costs are normally socialized, meaning that grid users pay them as a part of transmission tariffs. Congestion is dealt with usually either by changing the topology of the grid, or if the former proves insufficient by re-dispatching of generation units. The latter often takes the form of a balancing market, where

market players are paid for up and down regulation of their units or even for switching off the load, either partially of completely.
An alternative market organization is a centralized pool model. It implies that all energy transactions have to go via the organized market and that there is a uniform energy price in the whole control area. During the matching process the grid is treated as a copper plate, meaning that the cheapest generation gets priority no matter the grid limitations. In the second stage the feasibility of the achieved solution is examined. If there is congestion, some out-of-merit generators are dispatched at the cost of in-merit generators, involving financial compensation to these market parties who have to deviate from their planned dispatch. Among other, the cost of this action constitutes the uplift charge and is added to the energy price.
Locational Marginal Pricing (LMP) market is much different from the previous ones. The main difference is that LMP does not assume that the grid is a copper plate, but integrates its limitation directly to the power plant dispatch. LMP can be defined as a centralized, security constrained, bid-based, optimal economic dispatch, with energy pricing based on the marginal cost of supplying the next increment of electric energy demand at a specific location in the electric power network, taking into account both generation marginal cost and the physical aspects of the transmission system. As a result, there are different prices at different location in the transmission grid, the differences reflecting the congestion (or grid limitations for that matter).
LMP is often considered as the market organization as the nodal prices perfectly reflect all costs of supplying electricity at given nodes, at the same time managing congestion. It is the most market-based and economically efficient among all congestion management methods. Nodal prices send very clear signals to market players concerning the location of a new generating capacity or transmission lines. The drawback of LMP however is that it requires a central dispatch.

2.5.5.2 Cross-border congestion management methods (capacity allocation methods)

Cross-border congestion management aims at allocating the previously agreed upon amount of transfer capacity to market players wanting to trade between control areas. Therefore these methods can also be called capacity allocation methods. The most common methods applied at present are:

- Pro-rata rationing
- Priority based rules (such as first come, first served)
- Transfer Capacity Auctioning
    - Explicit or Implicit
    - Implicit Auction
- Market Splitting and Market Coupling

Pro-rata rationing

Pro-rata rationing is based on the principle of pro-rata curtailment of transactions. In other words, if demand for capacity exceeds the Available Transfer Capacity (ATC), all transactions are partially curtailed, in proportion to the requested capacity. However, this method provides neither the system users nor the system operator with any incentives as to an efficient use of the grid. On the contrary, the method may very likely induce unwanted behaviour such as gaming. Knowing in advance that there is congestion, market players may overestimate their capacity needs and by doing so secure the quantity requested. Anti-gaming measures such as obligation to use the designated capacity seem to be a necessity if the method is to be of any use.

On the other hand, as far as real time congestion management is concerned, this method will most likely remain to be used as a last resort during the emergency situations, efficiency becomes less of an importance.

Priority-based rules

Priority-based rules are characterized by the fact that they use published values of the ATC, and based on some simple mechanism allocate this capacity to the users of the transmission system. The allocation mechanism itself can differ depending on the implementation. The most common method uses chronological ranking of the reservations until the ATC is completely filled up and subsequent reservations have to be denied, as in first come first served principle.

The main drawbacks of priority-based rules are that they do not convey any economic incentive to market players. Moreover, this method favors long-term trade as such contracts always get priority over recent ones. Incumbents are implicitly favored at the cost of new players.

Transfer capacity Auctioning

Under Transfer Capacity Auctioning, market parties compete for transfer capacity by submitting bids. In the clearing process, the allocation of transmission rights is determined using an auction procedure. There are many variants of the capacity auctioning. However, the most important division is in explicit and implicit auctioning.

Explicit Transfer Capacity Auctioning makes a clear distinction between the transfer capacity and energy, both markets being separated. In the auctioning process, market players bid for transfer capacity that they want to reserve. Those who are granted capacity can, but do not have to use it. Hence the transfer capacity is reserved for the market party who bought it, not minding the energy prices.

Implicit Transfer Capacity Auctioning, on the other hand, combines the transfer capacity and energy markets. The capacity needed for a given energy transaction is implicitly reserved as a function of energy prices. The auction is actually an energy auction, the allocation of transfer capacity being a by-product of a power exchange matching process. Bids are submitted locally, and consist of quantity, price and zone information. The central auction office gathers all bid information and solves an optimization problem with constraints, maximizing total gains from trade calculated as gross utility minus cost of supply. Moreover, the zonal energy exchanges are limited by constraint stating that the power flow on a given interconnection must not exceed the allowed transfer capacities.

Both auctioning mechanisms could be organized over the single border, or over several border in a coordinated manner (i.e. in a flow based way). However, as the power flows in the meshed interconnected power system are interdependent, it is much better to allocate cross-border capacity in a coordinated manner. Several independent auctions in the same region can lead to infeasibilities, as transactions could incur unforeseen flows on other borders due to interdependencies of power flows in meshed networks, contributing to loop flows. Moreover, transactions between non-adjacent areas have to be split into single border capacity acquirements, or face the danger of being cleared unequally. Alternatively, security margins taken during the estimation of the transfer capacity have to be significant, leading to inefficient use of the scarce interconnections.

Market Splitting and Market Coupling as special forms of Implicit Capacity Auctioning

Market splitting is a congestion management method used in the Scandinavian electricity market Nord Pool. Nord Pool is a voluntary Power Exchange, with one interesting feature: cross-border transfer capacity market can be only accessed by submitting bids and offers to the Power Exchange. As a result, cross border transactions can be far better controlled and appropriately charged. Market splitting rests on the same principles as implicit capacity auctioning.

Market Coupling is a congestion management method proposed by the European Association of Power Exchanges, EuroPEX. Theoretically it is very similar to Market Splitting as both methods rely on the same principles as implicit auctioning.

2.5.5.3 Congestion Alleviation Methods

Congestion Alleviation Methods, as opposed to the former group, deal with real-time congestion. Their goal is to bring the system back to secure operating conditions.

Congestion as such, being a consequence of security limits violations, either thermal or stability related, is a problem of physical components, not of aggregated index values such as ATC or NTC. As the latter are calculated based on assumptions (i.e. base case scenario), they represent only an approximation of the reality forecasted on the previous day (D-1). On the actual day (D) the situation can be different calling for special measures. Usually the problem is not that too much power is transferred across the border, but that the cross border lines are not equally loaded, leading to overload of one line and surplus capacity on the other. Congestion Alleviation Methods can be seen as means to bring the system back to a secure operation by re-arranging the generation-load pattern i.e. re-dispatch of production units and/or shedding load.

The most common method to solve such situations, provided the severity of the problems renders topology changes ineffective, is re-dispatching of generation units. It comes down to the introduction of corrections to the initial generation dispatch, usually based on prices that generators communicate to the System Operator (SO) for up and down regulation. This service can be organized on an individual contract basis, or managed by a market, either integrated with a balancing market or separate. Two alternatives of re-dispatching actions can be considered. If the SO only intervenes within its own control area, the system can be optimized locally (internal re-dispatch). A more comprehensive approach involves several SOs trying to find a global optimum by re-dispatching units on both sides of the congested interconnector (coordinated re-dispatch). The latter has the advantage of being more efficient, since there are more nodes where power injections can be modulated. However, it requires a strong co-ordination between the SOs involved and a certain degree of harmonization of market rules in areas involved.

2.5.5.4 Financial Products – congestion hedging instruments

Generally speaking congestion is something that should be avoided. It decreases market value, being the sum of producer's and consumer's surpluses, by disallowing cheap, but remote, generation capacity and allowing more expensive local ones. Moreover, due to technical limitations, constant fluctuations of demand and non-storability, it is very difficult to predict prices, in turn translating into difficulties in making business decisions.

In order to guarantee an acceptable level of price stability, price risk hedging instruments have been developed. These financial products are derived from organized power markets and are not congestion management methods as such, but are rather complementary to them. They give a possibility to hedge against one's physical location and thus unstable prices. A result is that a company can be more certain of its price at the cost of having to pay slightly more on average.

Financial Transmission Rights FTR

An FTR gives the holder a right (or/and obligation) to a share of congestion rents received by the System Operator during congestion. The allocation of FTRs typically occurs as an auction, where the benefit of the buyer or seller is maximized. The auction determines the amount of FTRs allocated to market players and market clearing prices. The design of the auction is decided by the System Operator and depends on the market structure. FTRs are typically long-term and may have durations from months to years. They can take different forms such as point-to-point FTRs and flowgate FTRs, both of the obligation and option type.

Contracts for Differences CfD

Contract for Differences (CfD) is a risk management tool allowing to hedge against differences between a volatile price and certain value. There are different alternatives of CfD available. The CfD could hedge against the difference between two uncertain sport prices (i.e. regional price and a system price), or the difference between the spot price and a pre-defined reference price (or a price profile).

2.6 Congestion Management using FACTS devices

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The efficiency of the investment in transmission capacity is very related to the efficiency of utilizing the existing transmission system. In addition, system expansion for congestion management should ensure that the transmission system is flexible enough to meet new and less predictable power supply and demand conditions in competitive electricity markets. In these situations, along with the investment of the transmission network by adding new transmission lines, improving the system operation control capability and maximizing the utilization of transmission assets become very important. Applications of new enabling technologies are able to provide such solutions for electricity companies to maintain the stability and reliability of power systems while handling large volumes of transactions. One example of such enabling technologies is FACTS (Flexible AC Transmission Systems) controllers.

The development of FACTS-devices has started with the growing capabilities of power electronic components. Devices for high power levels have been made available in converters for high and extra high voltage levels. The overall starting points are network elements influencing the reactive power or the impedance of a part of the power system. Figure 2.16 shows a number of basic devices separated into the conventional control devices and the FACTS-devices. All the control devices listed in Fig. 2.16 may be used in congestion management depending on the nature of the congestion. However, series control devices are, in principle, more useful where power flow control is of primary objective.

The first column in Figure 2.16 shows the conventional control devices. The second column shows the FACTS-devices using Thyristor valves while the third column shows the FACTS-devices using converters.

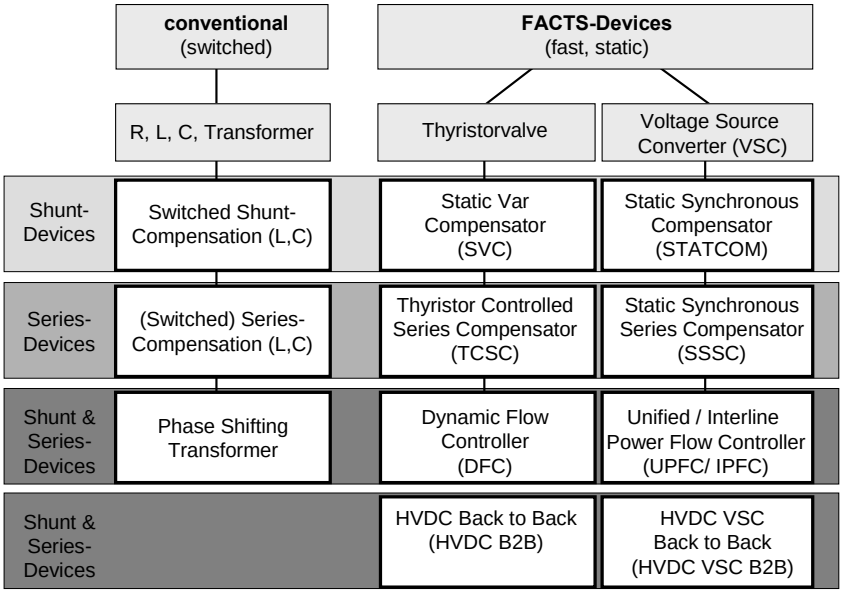

Fig. 2.16: Overview of major FACTS-Devices [2.10]

The third column of FACTS-devices contains more advanced technology based on voltage source converter technology such as Insulated Gate Bipolar Transistors (IGBT), Gate Turn Off (GTO) or Insulated Gate Commutated Thyristors (IGCT). It is anticipated that the applications of FACTS controllers will grow in power systems of the future, particularly in the deregulated electricity market environment. The ability of FACTS controllers to support and control power flows across borders of transmission networks is well recognized now. SVC (Static VAr Compensator) and TCSC (Thyristor Controlled Series Capacitor) are the first generation FACTS controllers. The Static Compensator (STATCOM) and the Static Synchronous Series Compensator (SSSC) are two types of the second generation of FACTS controllers that are based on power electronic switches, while the Unified Power Flow Controller (UPFC) is one type of the third generation, similarly based on power electronic controller. The UPFC has the advantage of controlling both active and reactive power flow simultaneously and independently. The use of FACTS controllers is advantageous as numerous environmental concerns restrict opportunities for network reinforcement through new transmission line construction.

In terms of congestion management, phase Shifting Transformers (PST) are perhaps the most common devices in practical use. For instance, PST (also called quadrature booster (QB) in the UK) have been used in the National Grid for some years. However, the limitation is the low control speed together with a high mechanical wear of components and frequent maintenance depending on the number of required operations. In the future, as an alternative, with their full and fast controllability, TCSC, SSSC and UPFC may be used in transmission congestion management. In recent years, it has been recognized that VSC HVDC can be used in renewable generation interconnections and power flow and voltage control, hence, congestion management.

Hundreds of FACTS devices, in particular SVCs have been installed since early 1970s with a total installed capacity of 90,000 MVAr. Table 1 shows the estimated number of worldwide installed FACTS devices and the estimated total installed power capacity. It can be seen that even the newer developments like STATCOM or TCSC show a quick growth rate in their practical application areas.

Table 2.1: Estimated number of worldwide installed FACTS-devices and their estimated total installed power

Type	Number	Total Installed Power in MVA
SVC	600	90,000
STATCOM	15	1,200
Series Compensation	700	350,000
TCSC	10	2,000
HVDC B2B	41	14,000
HVDC VSC B2B	1 + (7 with cable)	900
UPFC	2-3	250

Congestion management has become an important issue for TSOs since the deregulation of electricity markets. Efficient congestion management has become more difficult and complex to achieve than in previous decades because of the reality of finite energy resources, the influence of environmental concerns, and policies that prevent the construction of new generating stations and transmission lines together with the constraints of investment costs. In addition, FACTS technology will be a key technology to open the way towards smart transmission networks, which should be flexible, reliable, robust and efficient. Better management of existing transmission can help reduce, but certainly not eliminate, the need for new transmission.

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3 Frequency Control & Operational Reserve Requirements

3.1 General Discussion and Definitions

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Due to differences in the operating procedures, the technical definition of ancillary services may significantly vary depending on the considered power system. A common framework may be defined by coordinating authorities like UCTE in mainland Europe or FERC in Northern America. But these authorities are not system operators and they do not intervene in the operational working, unlike TSOs.

Nevertheless, a set of common features may be distinguished. In this section, definitions of the frequency control service are presented, as well as their technical features. A detailed survey comparing several power systems is found in [3.1]0.

3.1.1 Technical features of frequency control

The aim of frequency control is to maintain the balance between load and generation within a synchronous area. It is generally based on three control actions performed with distinct features: primary, secondary and tertiary frequency control.

Primary frequency control is a local automatic control that maintains load and generation in balance. This frequency control stabilises the frequency after a large disturbance.

Then, secondary frequency control is a centralized automatic generation control which brings frequency back to its reference value. Following an imbalance, it restores the interchanges with surrounding power systems in each control area.

Finally, primary and secondary reserves are restored by tertiary frequency control. This control is done by manual changes in the dispatching of generating units.

Due to the differences between the operation rules of systems, many terms are actually used to describe frequency control services, which can lead to misunderstanding. For instance, secondary frequency control is not used in the UK since the power system is operated by a single TSO without synchronous interconnection. Therefore the meaning of “secondary response” in UK is very different from the “secondary control reserve” of the UCTE. A detailed nomenclature of the different reserve classes is presented in Table 3.1. It refers to the previously described classification (primary, secondary and tertiary frequency control reserves).

Table 3.1: Names of the frequency control reserves in different systems (in [3.1]0)

	Primary frequency control reserves	Secondary frequency control reserves	Tertiary frequency control reserves			
PJM [33]	Frequency response	Operating reserve				Reserve beyond 30 min
		Regulation	Primary reserve		Secondary reserve	
			Spinning reserve	Quick start reserve		
CAL [16]	(no name)	Operating reserve			Replacement reserve and supplemental energy	
		Regulating reserve	Contingency reserve			
		Spinning reserve		Non-Spinning reserve		
DE [20]	Primärregelreserve	Sekundärregelreserve	Minutenreserve		Stundenreserve and Notreserve	
FR [19]	Réserve primaire	Réserve secondaire	Réserve tertiaire			
			Réserve tertiaire rapide 15 minutes		Réserve tertiaire complémentaire 30 minutes	Réserve à échéance ou différée
ES [34],[35]	Reserva primaria	Reserva secundaria	Reserva terciara			
NL [28]	Primaire reserve	Secundaire reserve	Tertiare reserve			
BE [17]	Réserve de puissance pour réglage primaire	Réserve de puissance pour réglage secondaire	Réserve de puissance pour réglage tertiaire			
GB [22]	Operating reserve	(does not exist)	Operating reserve		Contingency reserve	
	Response		Regulating reserve	Standing reserve	Fast start	Warming and hot standby
	Primary / Secondary					
	High frequency					
SE [36]	Frekvensstyrd Normaldriftsreserv and Störningsreserv	(does not exist)	Seven different types of reserves			
AU [13],[14],[15]	Contingency services	Regulating services and network loading control	Short-term capacity reserve			
	Fast / Slow / Delayed					
NZ [30]	Instantaneous Reserves	Frequency regulating reserve	(no name)			
	Fast / Sustained					
	Over frequency					

3.1.1.1 Primary frequency control

The primary frequency control is expected to manage deviations in the system frequency within a few seconds (short deployment time). In case of a steady-state frequency deviation, a generator participating in the primary control will change its power output according to the droop s_G defined below:

$$s_G = -\frac{\Delta f / f_n}{\Delta P_G / P_n}$$

With:

- ΔP_G being the steady-state change in generation
- P_n being the nominal output power
- Δf being the steady-state frequency deviation
- f_n being the nominal frequency

An illustration of the resulting control scheme is reported in figure 3.1, the power system being represented has an inertia. The primary frequency control consists in a proportional action on primary control power of generating units, in addition to the supplied scheduled and secondary control power.

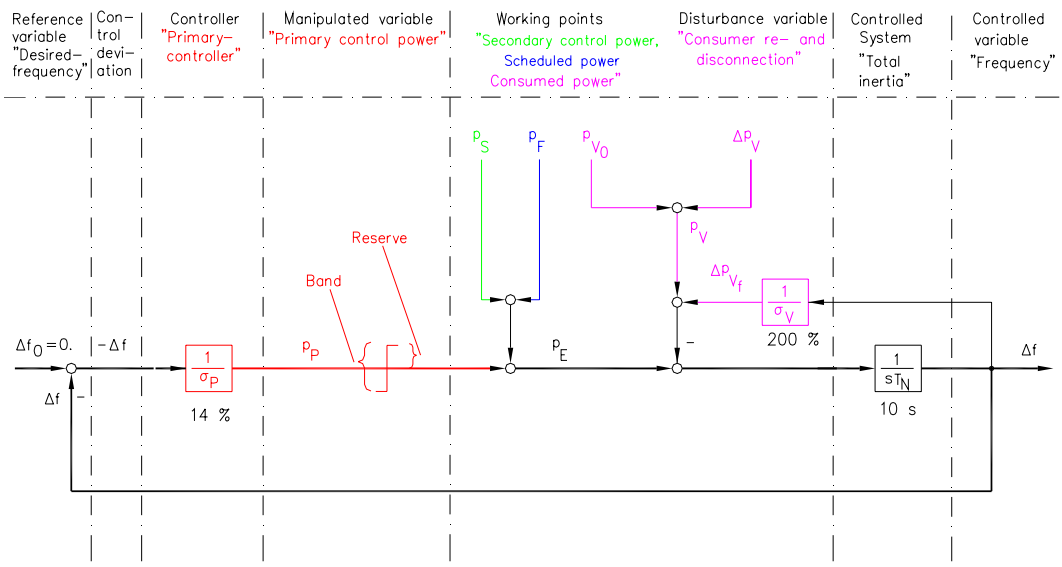


Fig. 3.1: Primary frequency control scheme

The performance of primary frequency control is linked with a set of parameters like: the deployment time, the droop of generators, the frequency deviation for which the entire reserve is used or the insensitivity of controllers. The primary frequency control parameters for different power systems are summarized in Table 3.2.

Table 3.2 : Primary frequency control features in different systems (in [3.1]

	NERC	UCTE	DE	FR	ES	NL	BE	GB
References	[24], [25], [26]	[29], [37]	[20], [21]	[18],[19]	[34]	[27], [28], [29]	[17]	[22], [23]
Full availability	No rec.	≤ 30 s	≤ 30 s	≤ 30 s	≤ 30 s	≤ 30 s	≤ 30 s	Pri.: ≤ 10 s Sec.: ≤ 30 s Hi.: ≤ 10 s
Deployment end	No rec.	≥ 15 min	≥ 15 min	≥ 15 min	≥ 15 min	≥ 15 min	≥ 15 min	Pri.: ≥ 30 s Sec.: ≥ 30 min Hi.: as long as required
Frequency characteristic requirement	10 %of the balancing authority's estimated yearly peak demand/Hz	20,570 MW/Hz	≈ 4,200 MW/Hz	≈ 4,200 MW/Hz	≈ 1,800 MW/Hz	≈ 740 MW/Hz	≈ 600 MW/Hz	Variable ≈ 2,000 MW/Hz
Droop of generators	5 % in 2004; no rec. anymore	No rec.	No rec.	3-6 %	≤ 7.5 %	5-60 MW: 10 % > 60 MW: 4-20 %	No rec.	3-5 %
Is an adjustable droop compulsory?	No rec.	No rec.	Yes	Yes	No rec.	5-60 MW: No rec. > 60 MW: Yes	No	Yes
Accuracy of the frequency measurement	No rec.	Within ± 10 mHz	Within ± 10 mHz	No rec.	No rec.	No rec.	Within ± 10 mHz	No rec.
Controller insensitivity	T: ± 36 mHz in 2004; no rec. anymore NI: No rec. I: No rec.	T: ± 10 mHz NI: No rec. I: should be compensated within the zone	T: ± 10 mHz NI: No rec. I: ± 0 mHz	T: ± 10 mHz NI: No rec. I: should be compensated within the zone	T: ± 10 mHz NI: No rec. I: ± 0 mHz	5-60 MW: T: ± 150 mHz; NI: No rec.; I: No rec. > 60 MW: T: ± 10 mHz; NI: ± 10 mHz; I: ± 0 mHz	T: ± 10 mHz NI: ± 10 mHz I: No rec.	T: ± 15 mHz NI: No rec. I: No rec.
Full deployment for or before a deviation of:	No rec.	± 200 mHz	± 200 mHz	± 200 mHz	± 200 mHz	5-60 MW: 30 % for ± 150-200 mHz > 60 MW: 70 % for ± 50-100 mHz	± 200 mHz	Pri.: -800 mHz Sec.: -500 mHz Hi.: +500 mHz

No rec.: no recommendation; Pri., Sec. or Hi.: primary, secondary or high frequency response; I: intentional; NI: non intentional; T: total.

For example, the primary frequency control of the UCTE synchronous zone is designed to cope with a 3000 MW loss of generation with a maximum steady-state frequency deviation of 200 mHz.

3.1.1.2 Secondary frequency control

Thanks to the primary frequency action, the frequency stabilises at a value different from its target value. Therefore, the secondary control must not only restore frequency but also bring interchanges back to their target value. This action is performed by a controller for the whole control areas or for control blocks within this area.
This control is required to minimize the Area Control Error (ACE) which represents the area's unbalance and its contribution to primary frequency control.

$$ACE = P_{meas} - P_{prog} + K_{ri}\,(f_{meas} - f_0)^2$$

With:

- P_{meas} being the measured value of the total power exchanged by the zone with other zones (positive in case of export)
- P_{prog} being the scheduled value of the total power exchanged by the zone with other zones
- K_{ri} being the K-factor of the control area in MW/Hz
- f_{meas} being the measured frequency
- f_0 being the nominal frequency

The action of secondary frequency control is commonly based on proportional-integral controllers so as to bring ACE to zero, as described in figure 3.2. The controlled system is made of generating units inertia and takes into account the supplied primary control power.

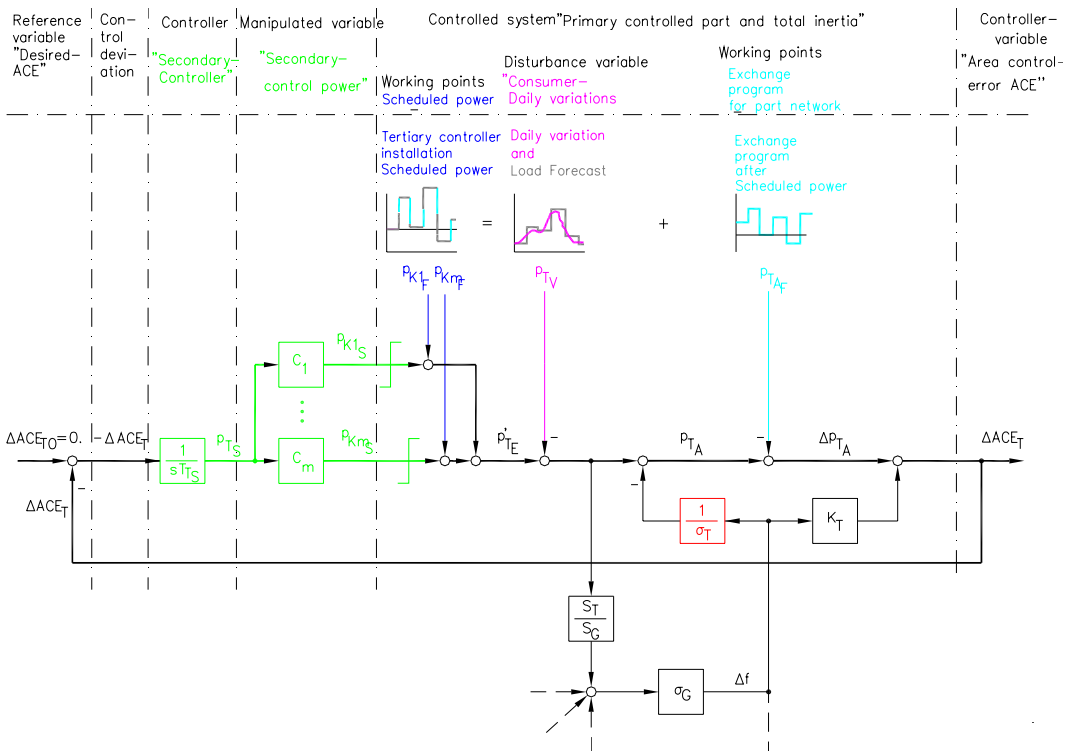


Fig. 3.2: Secondary frequency control scheme

[2] Written according to UCTE standards (with K_{ri} positive)

Each power system has its own set of parameters, as reported in table 3.3. Secondary frequency control leads to the end of the primary frequency control.

Table 3.3: Secondary frequency control features in different systems (in [3.1])

	NERC	UCTE	DE	FR	ES	NL	BE
References	[25]	[37]	[20], [21]	[19]	[34]	[27], [28]	[17]
Deployment start	No rec.	≤ 30 s	Immediate or ≤ 5 min	≤ 30 s	No rec.	30 s-1 min	≤ 10 s
Full availability	No rec.	≤ 15 min	≤ 5 min	≤ 430 s or ≤ 97 s	≤ 300-500 s	≤ 15 min	≤ 10 min
Deployment end	No rec.	As long as required	As long as required	As long as required	≥ 15 min	≥ 15 min and as agreed	As long as required
Control organisation	No rec.	No rec.	Pluralistic	Centralised	Hierarchical	Pluralistic	Centralised
Frequency measurement	ε ≤ 1 mHz T ≤ 6 s	1.0 ≤ ε ≤ 1.5 mHz T: No rec.	1.0 ≤ ε ≤ 1.5 mHz T = 1 s	ε ≤ 1.0 mHz T = 1 s	ε: Unknown T = 2 s	ε ≤ 1.0 mHz T = 4 s	ε ≤ 1.0 mHz T: Variable
Exchanges measurement	ε ≤ 1.3 % T ≤ 6 s	ε ≤ 1.5 % T ≤ 5 s	ε ≤ 1.5 % T = 1 s	ε ≤ 1.5 % T = 10 s	ε: Unknown T = 4 s	ε ≤ 0.5 % T = 4 s	ε ≤ 0.5 % T: Variable
Controller cycle time	≤ 6 s	1-5 s	1-2 s	5 s	4 s	4 s	5 s
Controller type	No rec.	I or PI	PI	I	P or PI, depending on the regulation zone	PI, with additional heuristics	PI
Proportional term	No rec.	0-0.5	Unknown	0	Unknown	0.5	0-0.5
Integral term	No rec.	50-200 s	Unknown	115-180 s	100 s	100-160 s	50-200 s
K-factor for measuring the ACE	The frequency characteristic	110 % of the frequency characteristic	Unknown	Unknown	Unknown	900 MW/Hz	≈ 660 MW/Hz

No rec.: no recommendation; ε: accuracy; T: cycle time; P, I or PI: proportional, integral and proportional-integral controller.

3.1.1.3 Tertiary frequency control

Tertiary frequency control is performed manually in order to restore primary and secondary reserves. As explained by [3.2], tertiary control may be achieved by connection/disconnection of generating units, changes in the dispatching of units, changes in the interchanges program or load control.

3.2 Effect of Wind Generation on Inertial Response

Contributors: Holger Mueller, Leslie Bryans

3.2.1 General Discussion

Whenever there is a mismatch between the active power output from generators and demand, the power system frequency changes. For a given power system condition, the greater the mismatch, the more rapid the frequency change.

The initial rate of change of frequency that occurs is purely related to the inertia of the power system at the time. Most wind generator technologies behave differently from conventional synchronous generators with regard to the inertia provided to the network, e.g. DFIG or full converter generators do not contribute to system inertia today although they could be designed to do so. Hence the overall system inertia in smaller network or islanding areas of a power system can significantly be reduced under high wind conditions. This will have an influence on the rate of change of power system frequency for the loss of generation or loss of an interconnector during import conditions.

Consequently the frequency will drop faster in the first seconds before primary control will start to operate. This can lead to higher frequency variations after disturbances and hence increased amount of load shedding, which could be needed. Similar results are shown in Fig. 3.3 and can be derived from the studies performed in [3.3], [3.4].

Many smaller power systems rely upon Rate of Change of Frequency (RoCoF) to detect power islanding. With increased Rate of Change of Frequency for the trip of a unit, such systems are likely to falsely detect power islanding. In such a case the protection relays have to be re-configured.

When wind generation is not equipped with LVRT control strategies (see section 5.3), a trip due to low voltages after a fault also causing a mismatch in active power balances can have negative impact on frequency control. As a result of the disconnection of further generation the increasing power unbalance is leading to even higher rates of change of frequency.

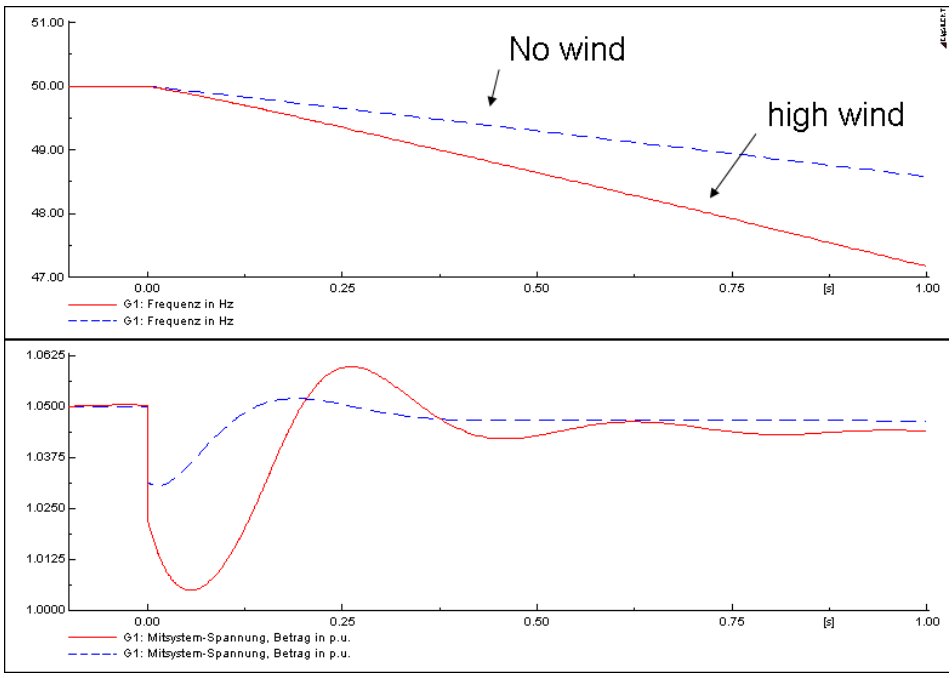


Fig. 3.3: Islanding of a network area with and without wind power [3.3]

3.2.2 Wind Turbine Inertia

All rotating plants have inertia. Each element of a rotating body contributes to the stored energy in the system. This energy is released as the body reduces speed. For a turbine system, the sum of all such elements in blades, hub, shaft, gearbox and generator rotor will be the stored energy. The problem becomes how to transfer this stored energy to the electrical system, which may be modelled as a rotating flux on the stator.

In the case of synchronous machines, the rotor is "flux-locked" to the stator and the retarding electrical system brakes the generator rotor thus extracting the stored energy. The rate of extraction of energy is therefore dependant upon the rate of change of frequency on the system.

Fixed speed induction wind generators behave in almost the same way, in that the turbine is effectively flux locked to the generator stator. Typically, they exhibit inertia constants in the range of steam turbine plants. This is often expressed on a per unit value in MWs/MVA installed. In the case of pure induction or fixed speed devices observation shows that the value lies between 4-5 MWs/MVA.

In the case of doubly fed induction generators, the flux link between the rotor and the stator is designed to allow a range of operating speeds to be accommodated. The power electronics provides power into the rotor at varying frequency to compensate for a difference in rotor and system speed. There is therefore no effective flux lock. This prevents the stored energy in the rotor from being extracted into the system as system speed falls. The inertia of such a device is therefore close to 0 MWs/MVA unless designed to behave differently.

It might be possible to detect a rate of change of system frequency and use this as a trigger for a change of control philosophy but that implies that the entire drive train can transmit the energy. That is under investigation with a number of present designs.

In the case of full converter machines, present control philosophy does not generally detect the change in system frequency as a means of extracting energy from the prime mover. The inertia constant of such a machine is therefore close to 0 MWs/MVA unless designed otherwise.

While some of the prime movers used could deliver the inertia into the converter system, it is not certain that the converter could handle the instantaneous loading placed upon it.

Potential solutions can be to

- Fit stored energy devices e.g. large flywheel generators or flywheel coupled synchronous compensators.
- Adopt alternative approaches to detecting power islanding and ensure main equipment is robust against RoCoF.
- Provide additional control of the wind generators to provide a 'virtual inertia' by a modification of the active power output during frequency deviations. This is the approach which has been followed by Hydro Quebec in their recent 2,000 MW Call for Tender.

3.2.3 Analysis of the Island of Ireland

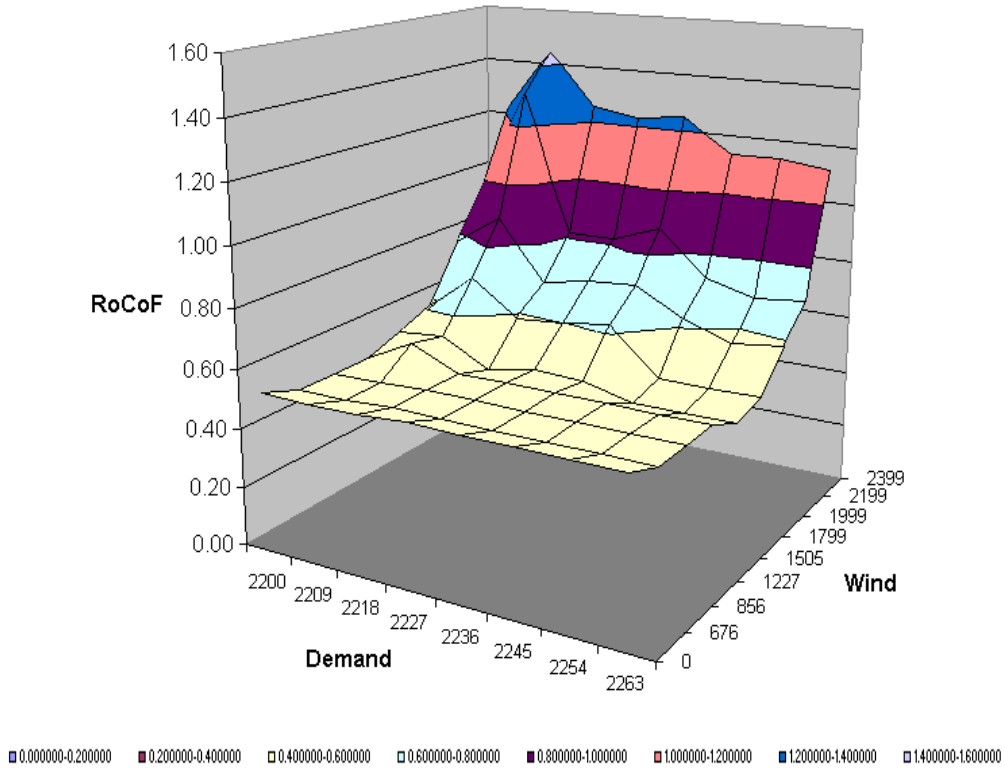


Fig. 3.4: All Island RoCoF study for varying amounts of Wind and demand on the System.

Fig. 3.4 shows the results of a study, performed by Northern Ireland Electricity, which examines the effect the varying amounts of wind can have on the Rate of Change of Frequency (RoCoF), for different levels of demand, for a certain generator trip. It can be seen that as the demand is increased the RoCoF is decreased; this is because there are more generators, with inertia, on the system. The higher levels of wind penetration cause lower system inertia and larger RoCoF values.

Although this surface graph was produced using simplistic calculations, points on the graphs have been validated by a more rigorous and reliable study. Clearly, the extreme dispatches may be unrealistic for other reasons, but are illustrative of the issue of falling inertia with higher penetrations of DFIG or full converter generators without inertial controls.

3.3 Technical Possibilities of Frequency Control With Wind Power Plants

Contributors: Harald Weber

3.3.1 Introduction

A dramatic increase is expected in the use of wind energy in Germany over the next few years [3.5], see Fig 3.5. Numerous wind farms are planned particularly in the offshore sector. The installed power of such wind farms lies in the region of a few 100 MW up to a few GW, and therefore in the magnitude of conventional power stations. These wind power stations no longer fall in the category of "distributed generation". The connection of these wind farms will entail a series of currently unresolved technical and physical problems.

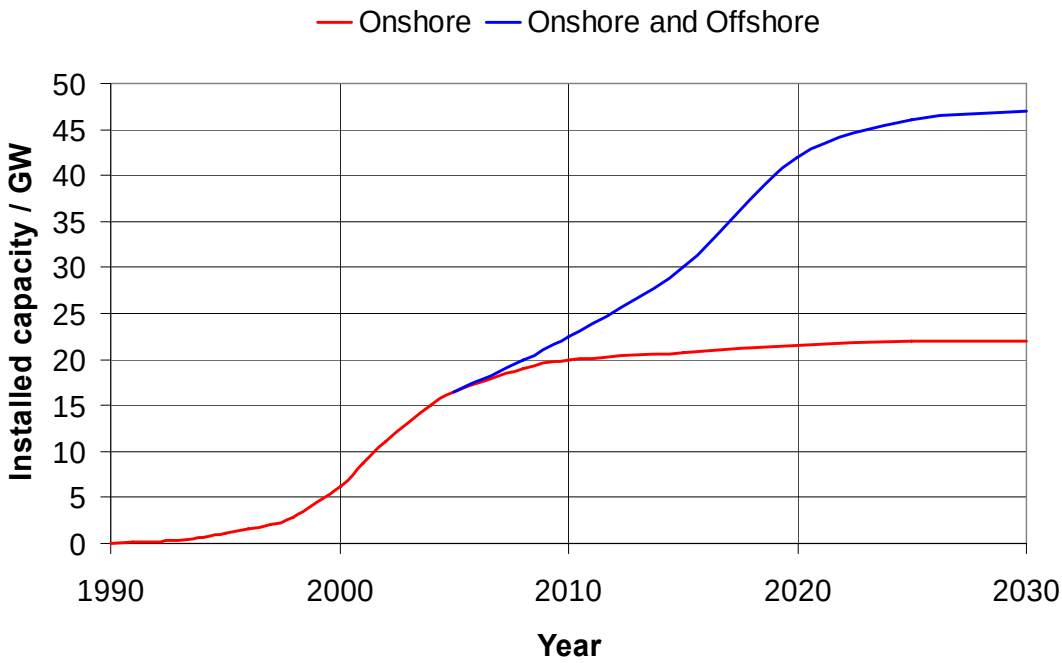


Fig 3.5: Forecast for the expansion of wind energy in Germany [3.5]

The centralised and powerful power feeds are predominantly into the North German extra-high voltage grid and are therefore remote in terms of load, i.e. power transmission is necessary over lengthy routes to consumer centres, which will necessarily result in an expansion of the extra-high voltage grid. Because of their dependency on wind, power feeds are variable and have an inherent fluctuation margin in terms of seconds, minutes and long term. In terms of their timing, wind power feeds do not correlate with the fluctuations in the grid load. As a result, there is an increased additional requirement for a regulatory function for frequency and voltage stability within the grid. Due to the increasing number of wind power stations the conventional power station capacity connected to the grid will be reduced and the remaining power stations would be increasingly repurposed into purely regulating power stations with the associated concerns for their profitability. In the past, wind turbines were approved under relatively low technical grid constraints. The primary objective in the operation of these units consisted in maximising the energy yield. Now, however, the

scheduled expansion in the use of wind energy needs to be rethought. To ensure secure grid operation in the future and the correct allocation of burdens between the operators of power station, transmission grid and wind farms, it has become necessary for wind power stations to accept new constraints within their capabilities. New binding grid connection rules for wind turbine generators have already been defined in Germany by a transmission grid operator [3.6]. New conditions governing turn-on, reactive power output and active power output as well as behaviour in the event of grid failures have been listed there. Nevertheless, the extent to which wind power stations are also able to take over the grid regulating tasks of the conventional power stations that they are replacing still needs to be examined. Modern rotational speed-variable wind turbine generators are either designed with a doubly-fed induction generator (DFIG) or with a synchronous generator and full-power converter. Both types of machine are ideally suited for rapid regulation of active and reactive power and/or voltage. Consequently, wind farms which are equipped with these machines essentially fulfil the requirements for taking on the constraints of regulating the grid [3.7]. In the following, the potential of a speed-variable wind turbine with pitch control will be examined with respect to its participation in primary control. It assumes the availability of both a positive and negative power reserve, which can very quickly be activated in response to grid frequency changes. The operation mode for pitch control generally in use today only allows a reduction in power, e.g. in strong winds or at excessively high grid frequency [3.6]. Up until now, it has usually been assumed that it is not possible to provide additional active power because wind speed, a factor that cannot be influenced, determines maximum power. Maximum power output has been targeted through the simultaneous optimisation of the pitch angle setting. However, if the wind turbine were operated without optimising pitch angle, this would also result in positive reserve power, which could be activated by adjusting the pitch angle. During normal operation, this would result in derated operating characteristics comparable with throttling in conventional power stations.

3.3.2 Operating characteristics of wind turbine generators with pitch control

Typical power coefficient curves c_P of megawatt-class wind turbines are illustrated in Fig. 3.6. The curves do not correspond to a manufacturer's specific blade profile. Similar to an efficiency level for a blade, cP indicates the power that can be taken from wind. It is clear from Figure 3.6 that there is an optimal pitch angle (here $\beta = 0°$) at which c_P is maximised and at which normal operation of the turbine is practical. Permanent operation of the turbine with $\beta = 0°$ and at the corresponding tip speed ratio $\lambda_{opt} = 9.2$ would result in the greatest power yield where $c_P = 0.5$. A reduction in power starting from this working point can be achieved by increasing the pitch angle to $\beta > 0°$. An increase in power, on the other hand, is not possible. If in contrast normal operation were to take place with a reduction in power given an increased pitch angle, for instance $\beta = 1°$, it could be possible to achieve an increase in c_P and therefore an increase in power by reducing the pitch angle.

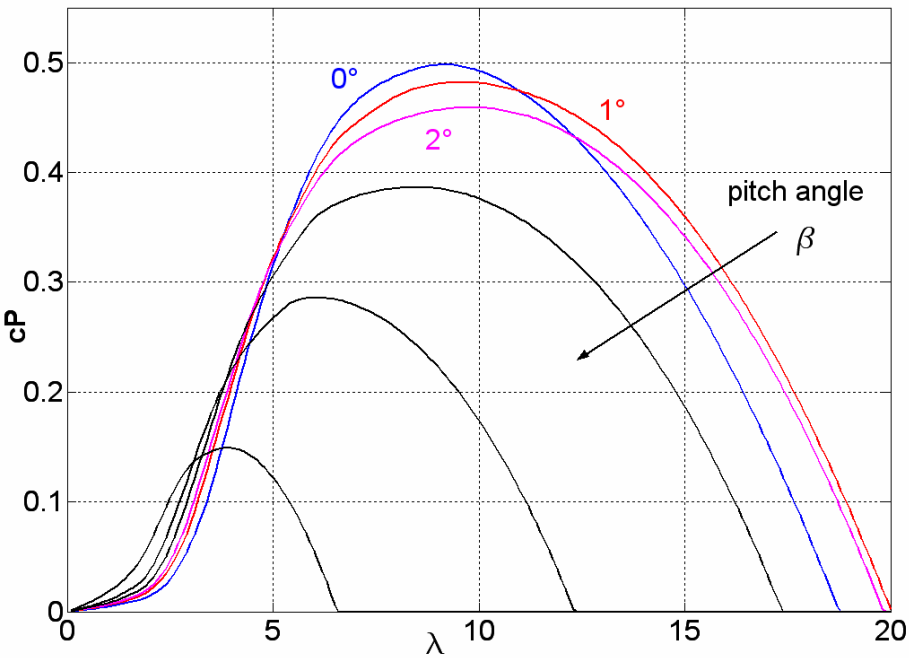


Fig 3.6: Power coefficient depending on tip speed ratio and pitch angle

A fictitious 5 MW wind turbine has been dimensioned using the blade profile illustrated in Figure 3.6. In Figure 3.7 the turbine power is illustrated for this turbine depending on the speed of rotation at various wind speeds. The influence of pitch angle is specified in addition. Different power curves result from different wind speeds (v1 and v2) according to the set pitch angle (β = 0º, 1º, 2º), whereby the attainable power decreases with an increasing pitch angle. The stationary working points can be read off by using the plotted control characteristics. For normal operation the operator will set an optimal control characteristic ensuring maximum power yield, and in the present example that would be where β = 0º. If it is planned to participate in primary control, then in contrast different operating characteristics, e.g. operating characteristics with a pitch angle of β = 1º would have to be specified. The operating of the turbine where β = 1º would then represent normal operation at reduced power. The two other control characteristics are then purely theoretical, if a particular quota of more or less power is to be provided at the same wind speed. Thus the maximum power yield is attained by the control characteristics where β = 0º, comparable with normal operation of the turbine without primary control. Control characteristics where β = 2º result in a further reduced power yield. An idealised illustration of the resulting control characteristics where β = 0º and β = 2º is set out in Figure 3.7. In practice, the actual control characteristics are non-linear and depend greatly on the blade geometry [3.7]. This can result in disadvantageous transient transitional behaviour when activating the power reserves. For a suitable conversion of the relatively large rotational energy, an increase in power should be associated with a reduction in rotation speed and vice-versa, as set out in the idealised illustration in Figure 3.7.

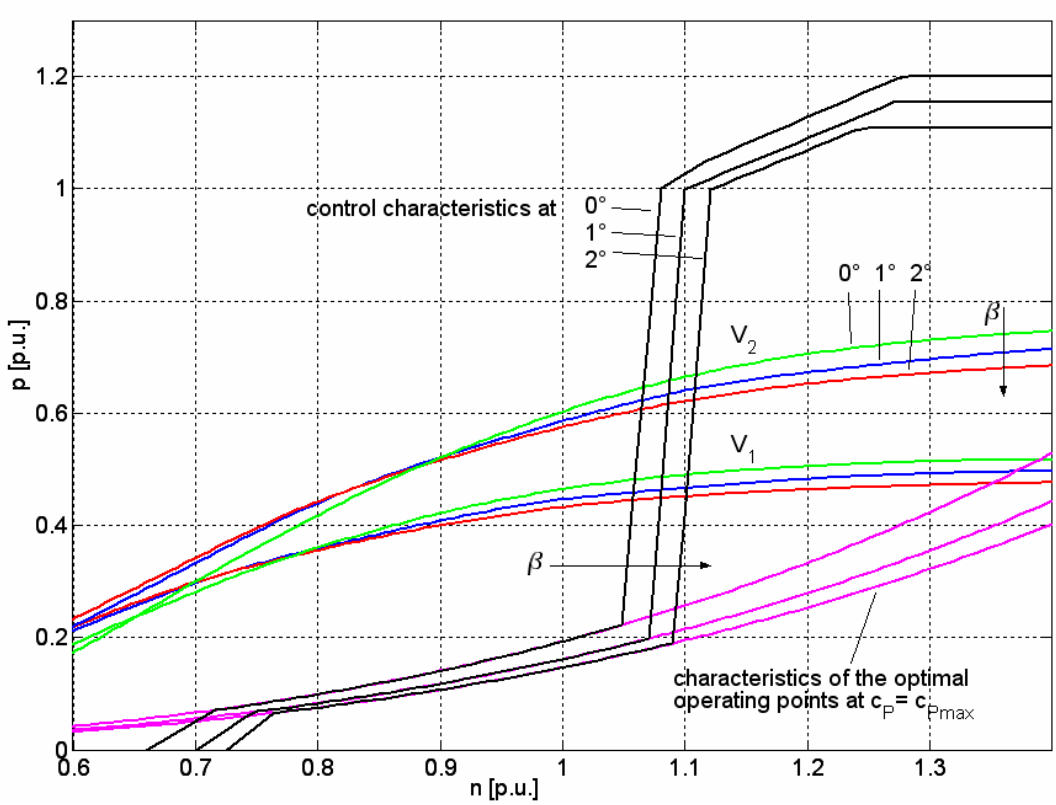


Figure 3.7: Power and control characteristics (idealised) for various pitch angles

3.3.3 Simulation

A model was created for the 5-MW wind turbine described in the previous section using the software Matlab/Simulink. Following conventional power stations, a primary control power of $\Delta P = \pm 4\%$ with a droop $\sigma = 10\%$ was set. This means that at a given frequency deviation in the grid of $\Delta f = \pm 200$ mHz, a control power of $\Delta P = \pm 4\%$ corresponding to the actual power output would be activated. Figure 3.8 shows the reaction of the wind turbine under wind conditions of v = 7 m/s and grid frequency changes of $\Delta f = 0$ mHz and $\Delta f = \pm 100$ mHz. The very rapid additional power increase and power reduction given a frequency drop respectively a frequency increase can be seen clearly.

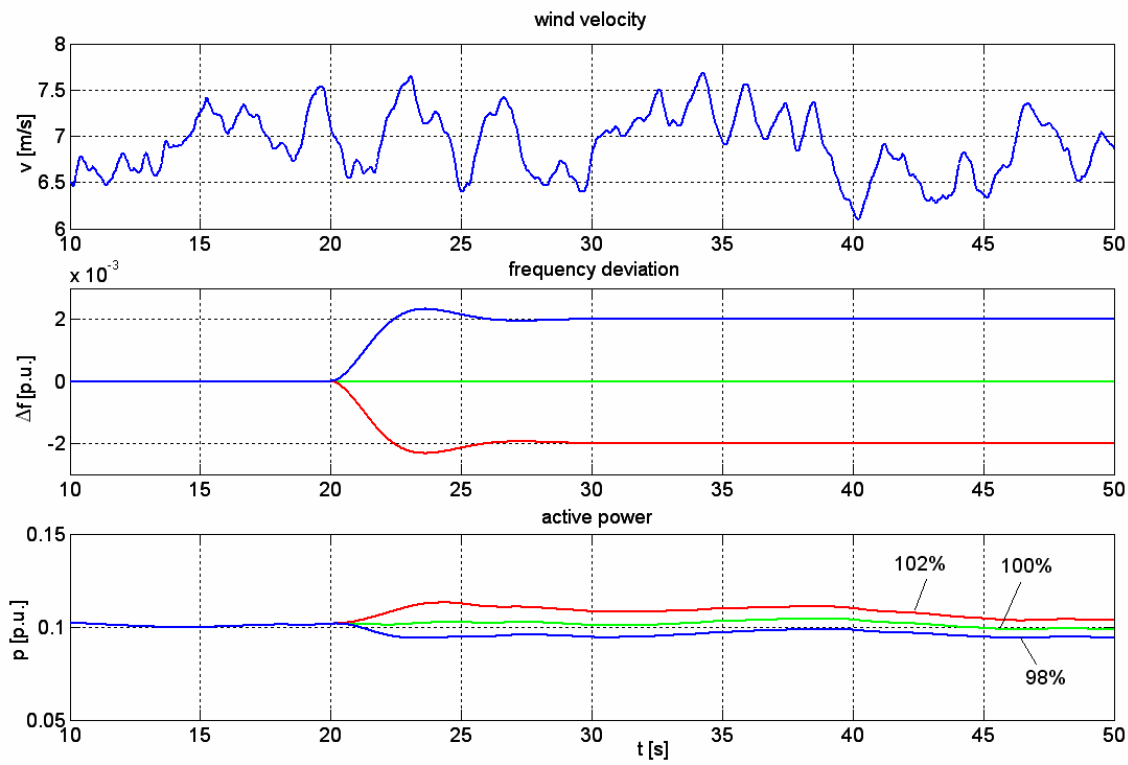


Figure 3.8: Performance of the wind turbine at different disturbances

3.3.4 Conclusion

The planned construction of numerous wind farms of the magnitude of conventional power stations calls for a new strategy in the operational management of the wind turbines. In terms of the connection conditions, wind farms should be equivalent to conventional power stations. Wind farms could take over the tasks carried out by the conventional power stations which they are replacing. This relates in particular to the provision of grid services, such as involvement in active and reactive power regulation and/or voltage regulation within the grid. This paper shows that in the case of the suggested method of operation of wind turbines, power can not only be decreased but also be increased within a time frame of seconds. Widespread use of this method of operation in all planned wind farms can result in a significant frequency-supportive seconds reserve power. Smoothing effects due to the distribution of both individual turbines and of wind farms further has the effect of significantly increasing the average wind power feed in terms of regulation for an activated power reserve.

3.4 Secondary Frequency Control

Contributors: Teruo Ohno, David Jacobson, Ivan Dudurych, Udaya Annakkage

As the integration of wind power progresses, growing concerns on the frequency control have been raised and discussed around the world. Influences to the secondary frequency control and utilities' efforts to overcome the difficulties are introduced in this section.

3.4.1 Load Frequency Simulation in Manitoba Hydro

Many utilities are considering using their operator training or Dispatch Training Simulator (DTS), which mimics the Energy Management System, to investigate operational questions related to integrating large amounts of variable generation. A DTS study may be able to more accurately quantify generation reserve requirements and impacts on NERC control performance criteria (CPS1 and CPS2). One of the major limitations of such a study tool is that it typically operates in real time. Some EMS systems can operate up to ten times faster than real time. Performing a large number of sensitivity studies is very time consuming. An alternative simulation approach is being developed to overcome this limitation and is described below.

3.4.1.1 Simulation Model

The inertias of all the rotating machines in the Manitoba Hydro (MH) system (including synchronous condensers) are lumped together as a single rotating mass. The generating units are grouped into two categories for the purpose of modeling their governor and turbine responses. The units equipped with automatic generation control (AGC) are modeled by a single governor-turbine model. Similarly, the remaining units are modeled by another single governor-turbine model. The power flow in the HVDC line is modeled as a negative load added to the system. The model allows the HVDC line to be on AGC duty, in which case the AGC will generate raise/lower signals to generators on AGC as well as the HVDC line. A simplified block diagram of the load-frequency model is shown in Figure 3.9.

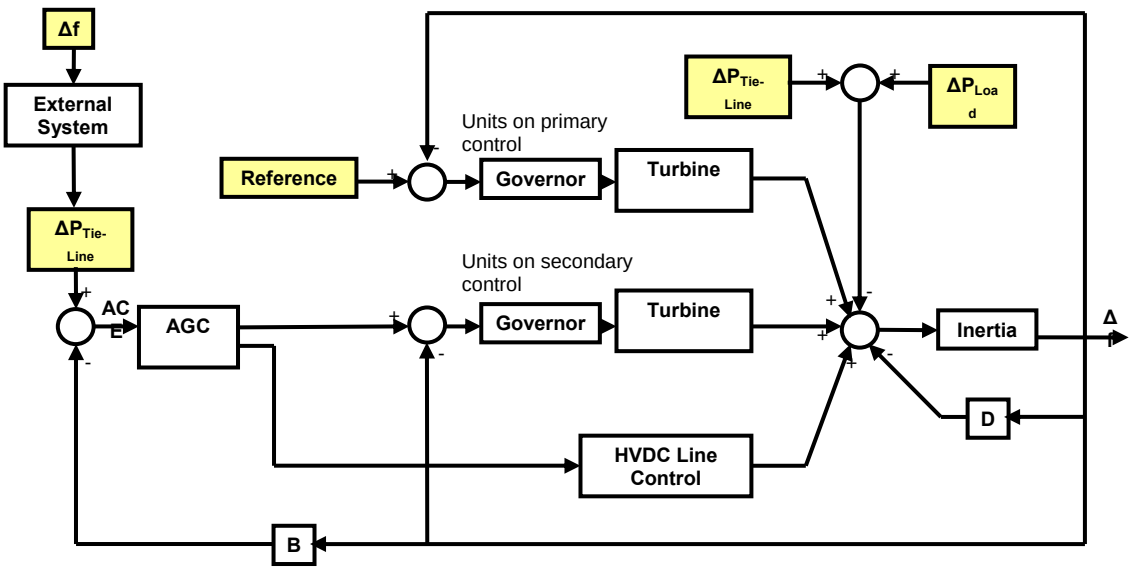


Fig. 3.9: Manitoba Hydro load-frequency model.

The response of the AGC depends on how large the Area Control Error (ACE) is. The following scheme used in Manitoba Hydro is incorporated into the model.

- Deadband region: ACE<20 MW
- Regulate region: 20<ACE<35 MW - 24 second delay before units move (Grand Rapid units are in this mode of operation).
- Assist region: 35<ACE<150 MW - all units selected to regulate will move (HVDC line is in this mode of operation)

The emergency region is defined as the region where ACE is greater than 150 MW. For the simulations carried out in the present study, this region is not encountered and hence not modeled.

Any deviations in MH frequency results in a deviation of tie line power flow to other areas. This is modeled using an equivalent external system comprising an inertia and damping. The tie line is modeled using an integrator with its gain representing the synchronizing coefficient of the line.

The simulated frequency deviation and tie line power deviation are sampled at 4 second intervals to compute the area control error (ACE). The 4.0 second sampled values of frequency and ACE are then used to compute their clock minute average values and subsequently the CPS1[3] for the hour.

The modeling tool chosen for this work is PSCAD/EMTDC. All the generators in the southern MH system can be individually switched on or off at the beginning of each simulation using switches provided in the model. The net inertia of the system is calculated based on the on-off status of generating units and synchronous condensers. The initial power set points of all the generating units and the set points of the two HVDC bi-poles at the beginning of the hour can be entered as initial settings. The control modes of HVDC bi-poles and the units on AGC duty can also be entered using the switches provided in the model.

The model is validated using recorded data collected over the month of May in 2006. Several randomly selected one hour intervals were used for the validation. The recorded load variation is input to the model, and the frequency deviation and tie line power deviation are simulated. The turbine and governor parameters were set at typical values. Three of the parameters in the model; the load-frequency sensitivity (load damping), the gain, and the time constant of the external system model were tuned to get a good comparison of recorded and simulated frequency. Comparisons of the system frequency and tie-line power deviation for May 01, 2006, 9:00 am to 10:00 am are shown in Figure 3.10. It can be seen that the frequency obtained from the simulation model match closely with that of recorded data. The tie-line power deviations follow the trends, but not as closely as the frequency.

[3] NERC standard BAL-001-0a specifies performance bounds on frequency deviations resulting in deviations in ACE. CPS1 is a bound on the 1 minute average of ACE and CPS2 is a bound on the 10 minute average of ACE. See ftp://www.nerc.com/pub/sys/all_updl/standards/rs/BAL-001-0a.pdf

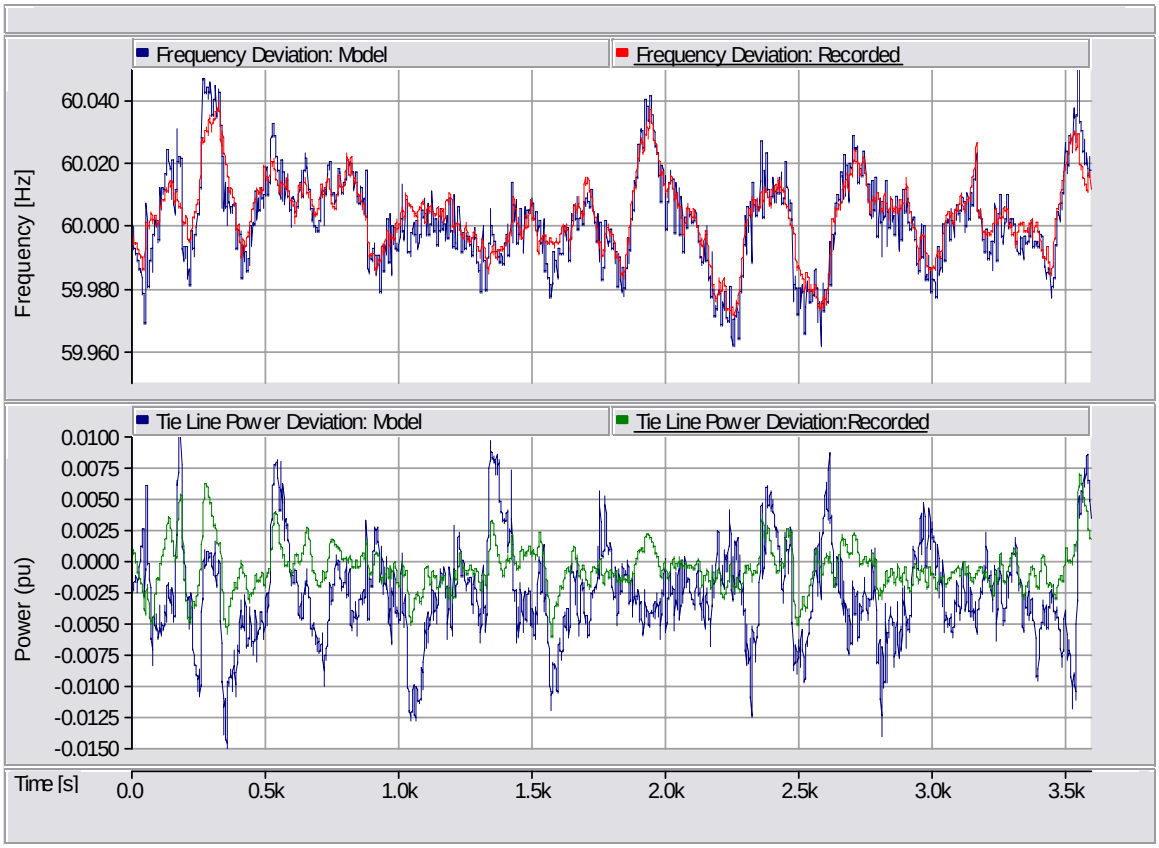


Fig. 3.10: Comparison of Simulated and Recorded data for May 01, 9:00 am to 10:00 am.

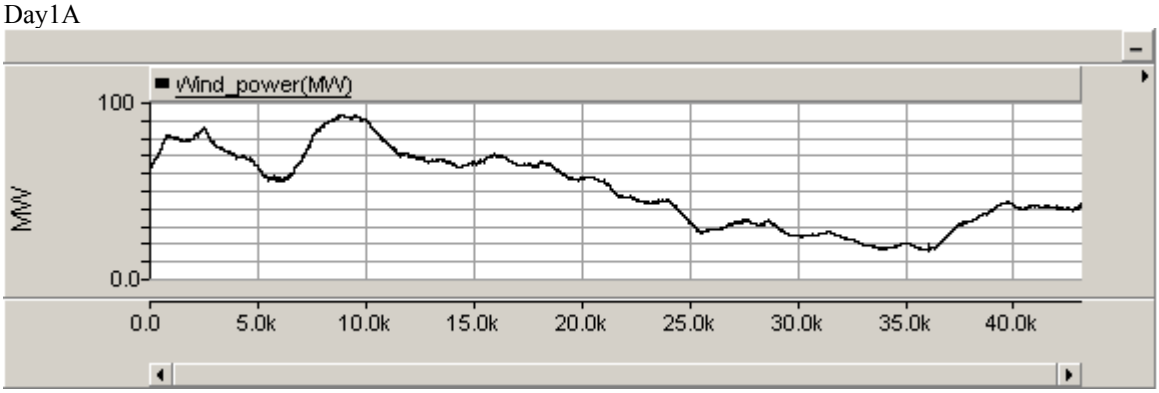
3.4.1.2 Simulation Results

The load-frequency model has been shown to match tie-line power flow and frequency variations fairly closely over a one hour simulation time frame. However, calculating the NERC CPS1 index exactly using the simulated data has not been completely successful. Although the CPS1 index is not accurately predicted with the present model, it can be used for sensitivity studies.

The effect of wind power variation was studied using the recorded wind power output of a wind farm (100 MW nameplate) over a 12 hour period sampled at 4.0 second intervals. Two representative samples of data that were used are shown in Fig. 3.11.

Simulations were repeated with a scaling factor of 2 and 4 applied on the actual recorded wind power variation shown in Fig. 3.11. For each 12 hour simulation, the CPS1, CPS2, and the regulating reserves used from Grand Rapid Units and the HVDC line were recorded. Simulations show that CPS1 index deteriorates with increased wind variation, as expected. The CPS2 index is 100% for most cases, but a slight decrease is observed when the scaling factor was 4.

Day1A



Day2B

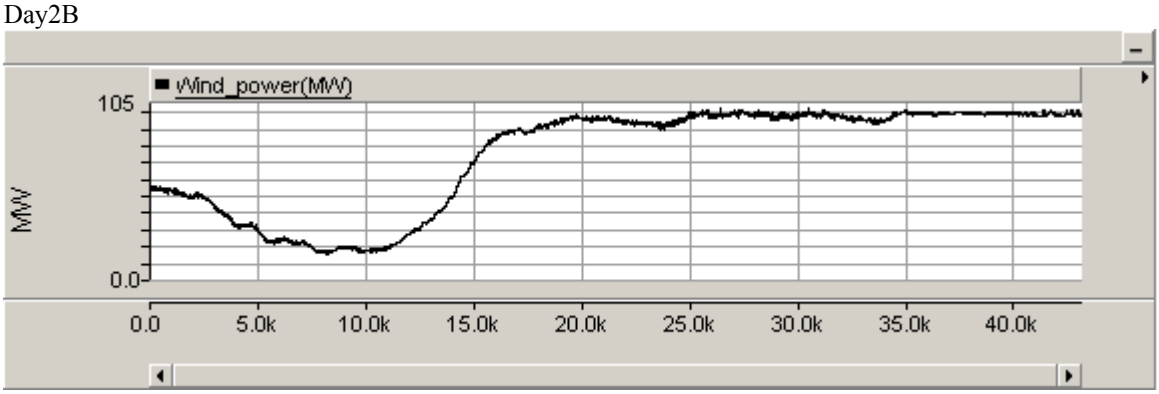


Fig. 3.11: Two representative 12-hour operation periods of a 100 MW wind farm (4 sec. data).

The maximum regulating reserve required in the 12 hour period is shown in the tables below. The regulating reserve required from Grand Rapids increases as the scaling factor is increased. There is no contribution from the HVDC line in most simulations because the ACE is not big enough to enter the Assist region. For the wind data set, Day2B, with a scaling factor of 4, there is almost equal contribution from the Grand Rapids and the HVDC lines. For the same case with AGC gains increased by a factor of 2, the Assist mode is not encountered and thus the HVDC does not contribute to regulation.

The above simulations were repeated with the AGC gains increased by a factor of 2. In all cases the CPS1 index improved with the increased gain.

AGC Gain=1

Data set	Scale Factor	Grand Rapids Change in Power (MW)		HVDC Change in Power		Tie line power deviation		CPS1	CPS2
		min	max	min	max	min	max		
Day1A	1	-1.26	33.40	-11.76	-11.76	-19.56	9.56	127.86	100.00
	2	-7.77	48.38	-11.76	29.29	-25.82	22.64	73.99	100.00
	4	-8.55	203.60	-73.34	-11.76	-26.96	39.06	-72.29	100.00
Day2B	1	-8.32	23.41	-11.76	-11.76	-20.79	18.23	43.81	100.00
	2	-19.56	41.12	-42.55	19.02	-25.72	39.72	-53.62	100.00
	4	-17.70	65.66	-134.91	70.34	-25.67	46.09	-65.22	97.18

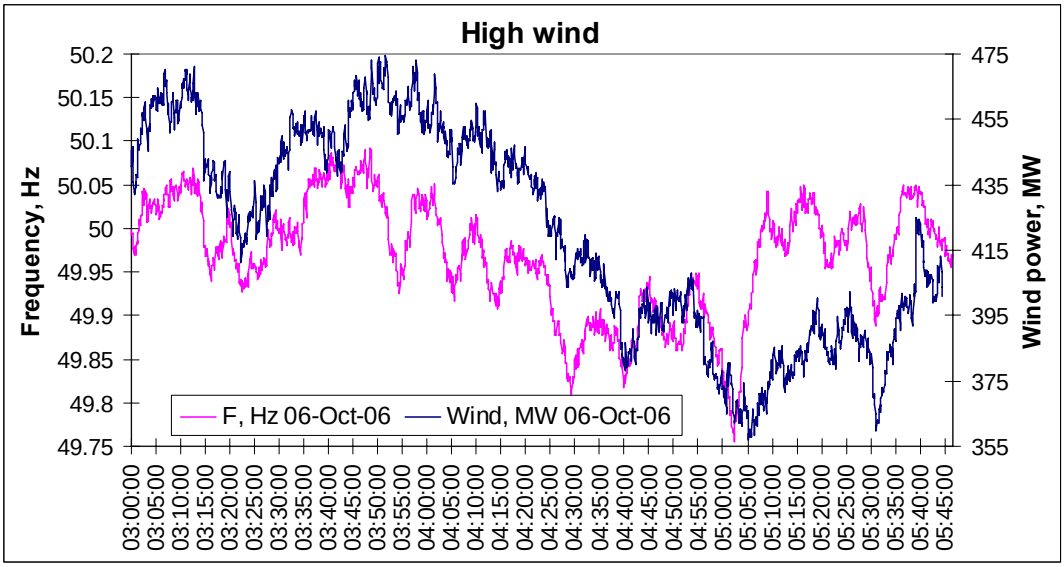
AGC Gain=2

Data set	Scale Factor	Grand Rapids Change in Power (MW)		HVDC Change in Power		Tie line power deviation		CPS1	CPS2
		min	max	min	max	min	max		
Day1A	1	-1.26	35.51	-11.76	-11.76	-15.20	9.56	139.79	100.00
	2	-17.10	82.02	-11.76	-11.76	-17.91	18.62	104.46	100.00
	4	-24.74	219.83	-52.81	-11.76	-24.10	38.90	-16.82	100.00
Day2B	1	-10.61	27.29	-11.76	-11.76	-15.86	22.84	58.77	100.00
	2	-16.92	66.36	-11.76	52.81	-16.78	27.36	54.14	100.00
	4	-44.93	144.68	-114.39	-11.76	-19.78	27.27	3.09	100.00

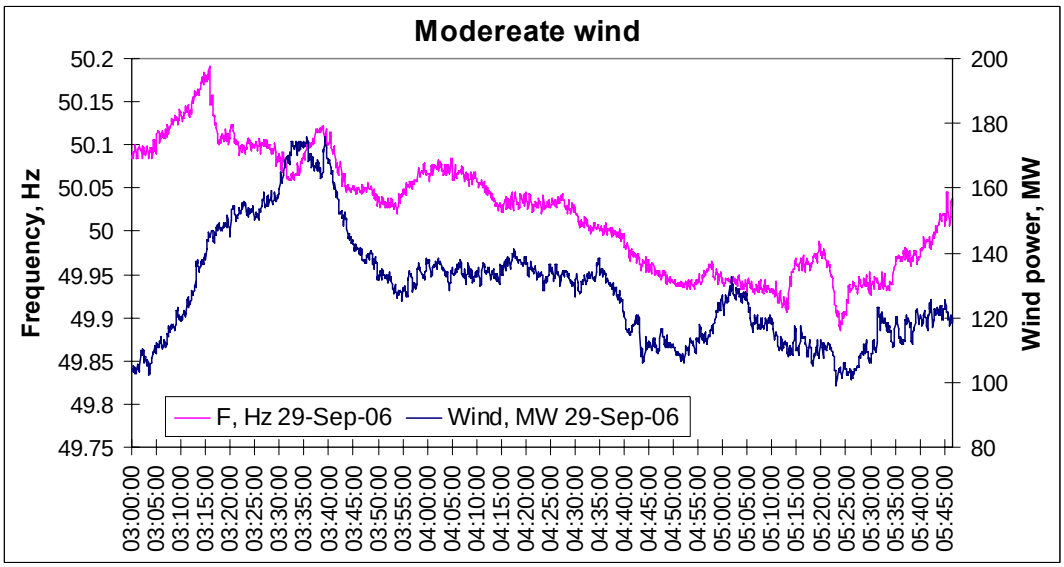
The simulations were also repeated with a ramp rate (2 MW/min) imposed on the wind power variation. The effect of imposing a rate limit is not as significant as the effect of increasing the AGC gain.

3.4.2 Influence on Secondary Frequency Control in Ireland

Power system controllers report on growing difficulty to control frequency when wind output is high. In Figure 3.12a, there is an example showing the direct effect of wind power variation on frequency variation in Ireland. Here the wind power output was between 50% and 70% of the total wind power generation capacity. For comparison reasons, wind power output versus frequency profile is shown for the same day in the previous week in Figure 3.12b, when wind power output was moderate. It is seen from the comparison that frequency control becomes very difficult when frequency changes due to wind are reaching 1.5 Hz/min. At present such changes force power system operators to move responsive plant more frequently than previously. Higher wind power proportion in the total generation (especially during night load valley) potentially can lead to unwanted under-frequency protection operation, spurious load shedding and operating reserve actuation.



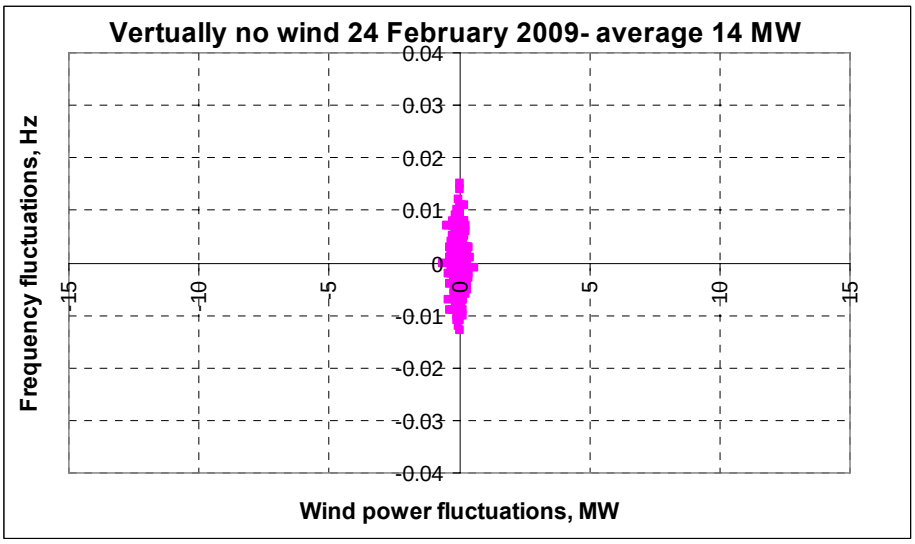
(a)



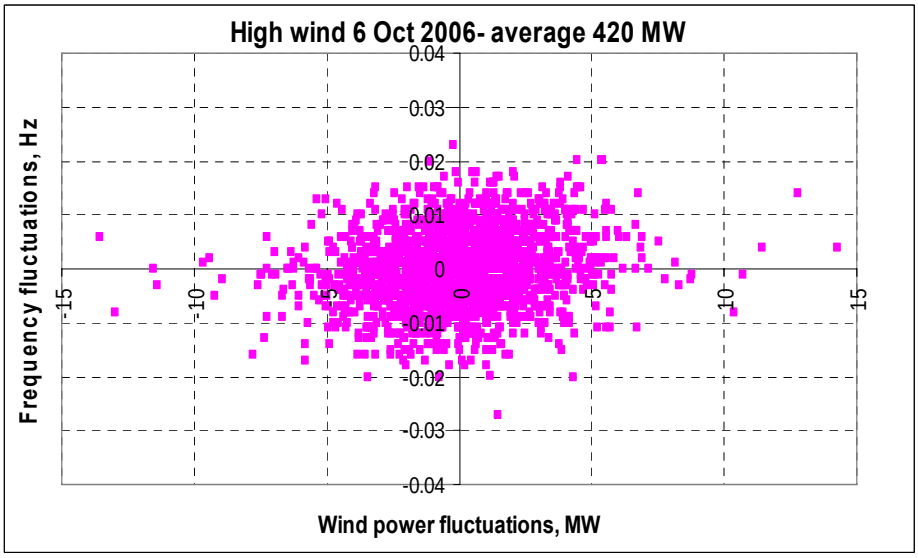
(b)

Fig. 3.12: Total wind power output versus frequency for: (a) high wind and (b) moderate wind.

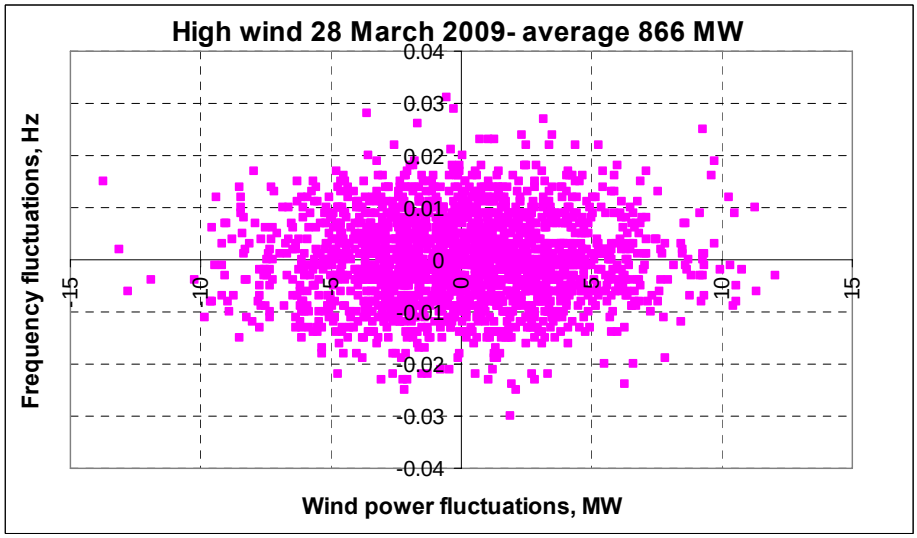
Operation experience with high level of wind generation, especially during the night shows very strong correlation between wind power and system frequency fluctuations. In Figure 3.13, frequency fluctuations (Hz) in 5-sec time frame are shown as a function of wind power output fluctuations (MW) during morning hours at three different levels of wind penetration on the system. It is clearly seen from the figure that high wind produces more frequency fluctuations and in a wider range. Statistical data analysed on extreme changes in wind power output suggests that they could influence reserve requirements.



(a)



(b)



(c)

Fig.3.13: Frequency fluctuations versus wind power output fluctuations for: (a) low wind, (b) moderate wind, and (c) high wind

Present levels of wind power penetration already affect established operating reserve margins for short periods of time (minutes). With higher wind power penetration levels, reserve requirements may be revised. This could be done in conjunction with establishing and improving the wind following capability of the conventional plant.

For the estimation of operating reserve requirements due to the wind, wind power output fall offs within 10 seconds, 75 seconds, and 3.5 minutes have been analysed. Based on maximum values within these time intervals, proposals are made to increase existing primary reserve (5 - 15 seconds) by 2.5 % of installed capacity of wind generation; for the secondary operating reserve (15 - 90 seconds) - by 4%, and for the tertiary operating reserve (90 seconds – 5 minutes) - by 5 % of installed capacity of wind generation.

Replacement reserve or long-term reserve (tens of hours) should be equal to maximum export capacity (MEC) of the wind generation, as our records clearly demonstrate periods as long as four days of virtually no wind power output.

3.4.3 Influence on Secondary Frequency Control in Japan

Fluctuation of wind power can be a serious threat to island power systems, such as in Japan. In order to maintain frequency within a certain range from its nominal value, it is necessary to have an appropriate LFC capacity, considering the fluctuation of wind power as well as the fluctuation of system load.
In order to evaluate the fluctuation of wind power, Japanese utilities monitor the wind power output. Figure 3.14 shows the wind power output[4] in one of the Japanese utilities that has the largest share of wind integration in Japan. By measuring these wind power outputs, Japanese utilities are trying to estimate the maximum total fluctuation that has to be compensated by LFC capacity of other generators.

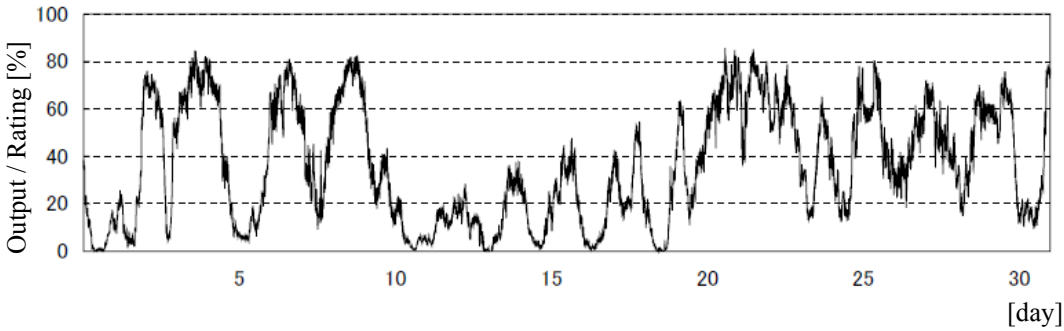


Fig. 3.14: Wind power output in Tohoku Electric Power in December 2003

Some Japanese utilities set tentative ceilings to wind installations without any additional measures, based on the typical LFC capacity (1-2% of system capacity) at a bottom demand. Maximum permissible fluctuations have been found from the following inequality where load fluctuation and wind fluctuation are assumed to have no correlation and cross rectangularly each other (see Figure 3.15), and verified by load frequency control simulations. In the inequality, the ratio α is found from the wind fluctuation in Figure 3.14.

[4] Tohoku Electric Power: "Result of the Analysis on the Allowable Interconnection Capacity of Wind Power to the Network of Tohoku Electric Power (in Japanese)", [Available on the web: https://www.tohoku-epco.co.jp/oshirase/newene/04/pdf/h18_temp01.pdf]

$$\text{Total fluctuation} \leq \text{Allowable deviation between supply and demand}$$
$$\Downarrow$$
$$\sqrt{(\text{Load fluctuation})^2 + (\text{Wind fluctuation})^2} \leq \sqrt{(\text{LFC capacity})^2 + (\text{Permissible control error})^2}$$
$$(\text{Wind fluctuation} = \text{Total wind power rating} \times \alpha)$$

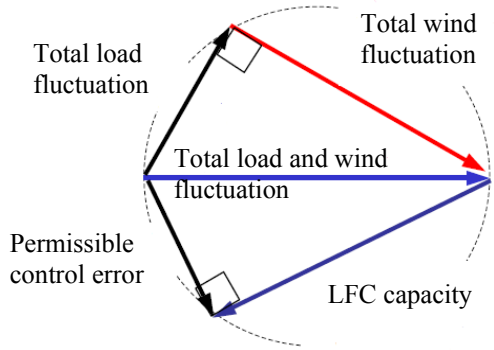


Fig. 3.15: Schematic of relation between fluctuation and LFC capacity

3.5 Reserve requirements

Contributors: Ivan Dudurych, J. C. Smith, Jerome Duval

3.5.1 General features

Each TSO has to define a security margin for each time horizon based on an acceptable level of risk. The TSO must ensure that there is enough available reserve to guarantee the reliability of the system (day ahead or in real time).

The amount of required reserves has to be large enough to face either forecasts errors or contingencies like the loss of the biggest generating unit. The load/production balance is usually maintained thanks to three levels of control. Primary and secondary controls are fast automatic, unlike tertiary frequency control, as reported above. Tertiary frequency control is based on manual change of the generation unit dispatching and commitment. The aim of tertiary reserve is to restore primary and secondary reserves and to make large generation adjustments if required.

3.5.2 Security margins and required amount of reserves

The required amount of reserves is based on the assessment of the operating reserve margins of the power system, as explained in [3.8]. This margin is derived from the difference between the expected total available production and the forecasted load at a given time horizon. For example, in France, the 15 minutes margin is made of secondary and fast tertiary reserve and is expected to manage the loss of the biggest generation unit (which represents about 1500 MW).

For instance, considering a gaussian distribution of forecasts errors, the reserve required to manage 99,7 % of all variations in load due to the forecast error would be sized to ± 3 times the standard deviation of forecast errors at the given time horizon[5].

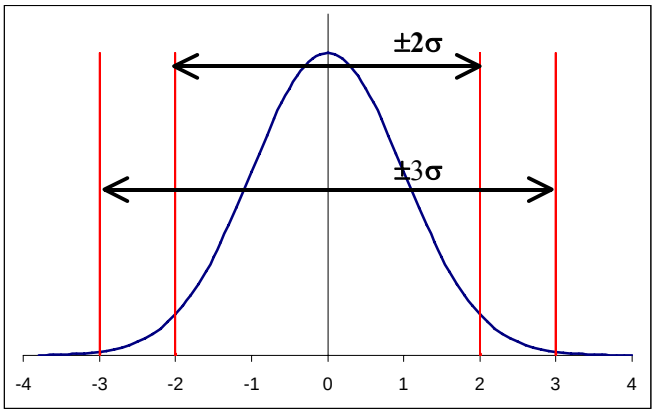


Fig. 3.16: Gaussian distribution with respect to the standard deviation

If we add the uncertainty of available production (conventional and wind), the reserve must be[6] as follows to merge 99.7 % of all situations, (UK Energy Research Centre [3.9]):

- $reserve = \pm 3\sqrt{\sigma_L^2 + \sigma_P^2}$ (+ disturbance reserve) without wind power
- $reserve = \pm 3\sqrt{\sigma_L^2 + \sigma_P^2 + \sigma_W^2}$ (+ disturbance reserve) with wind power

(where σ_L, σ_P, σ_W are the standard deviations of forecast errors of load, available production and wind power generation)

As a consequence, an increase in variable production capacity (mainly wind power) will result in an increased need for reserves.

3.5.3 Methodology to assess the impact of wind power on tertiary control requirements

Until now, power systems had to face contingencies such as load variation and sudden unavailability of generating units. The increasing amount of wind power has introduced a new source of uncertainty in the system. The impact can be reduced by limiting the forecast error. Therefore, the accuracy of wind production forecast will have a great impact on additional needs for reserves.

Forecast methods:

The accuracy of generation forecasts depends on the forecast method and the forecast time scale. Many different types of forecast methods may be used (statistical-model-base, physical-model-based…).

[5] The required time horizon is linked with the considered system operation rules. The forecast error standard deviation will of course increase with the forecast time frame.

[6] On the assumption that no correlation exists between load and supply variations and that these variations follow gaussian distributions.

If the considered wind production generation is distributed over a large geographic area, forecasting will take advantage of the resulting smoothing effect.

Among all existing forecast methods, a persistence forecast method produces good results with very low cost within the time frame of power system operations. Persistence forecast is based on the assumption that the forecasted generation for the next time step is equal to the wind power injection of the last time step. As a consequence, forecast error is given by real wind power fluctuation during the time step. Therefore forecast error is characterized by the standard deviation of these power fluctuations.

Impact on reserves requirements:

Standard deviations of wind power fluctuations are given in [3.10] for different time scales, as reported in Table 3.4. This NREL study considered a wind farm comprising 138 wind turbines of 0.75 MW each.

Table 3.4: Standard deviation of wind power with Pn = 100 MW, depending on the time frame (in [3.10])

Time frame	**Standard deviation σ of ΔP (installed capacity of considered wind park: Pn = 100 MW)**
1 second	0,1 to 0,2 % of P_n
1 minute	0,5 to 1 % of P_n
1 hour	7 to 11 % of P_n

The installed capacity of the considered wind farm is 100 MW, but standard deviation would be much lower if several wind power plants were aggregated over a large area. If 10 GW of wind were considered in the UK, the standard deviation of wind power variations would be 1.4 % at a 30-minute time horizon, 9.3 % in the case of four hour forecasts according to a DTI[7] study [3.11].

For time frames ranging from seconds to minutes, and due to the smoothing effect of the geographical dispersion of wind farms, wind power fluctuations are limited in comparison to contingencies like generation unit losses[8]. Therefore, these fluctuations have a weak impact on primary reserve. But it may result in an increased use of secondary frequency control.

However, for the hour time frame, wind power fluctuations are significant and must be taken into account for the assessment of the required amount of reserve. For this time frame (hours), the impacted reserve is the tertiary reserve (manually activated).

Practical assessment of reserve requirements:

The additional need for tertiary reserves is usually estimated through the comparison of the forecast errors of load and so-called “net load” (which is equal to the load minus wind generation). For short time period, the persistence method is used and the forecast errors are strongly linked with the fluctuations of these two values during one time step. This estimation

[7] UK Department of Trade and Industry

[8] However, wind power fluctuations can be large if wind farms do not have good Fault Ride Through (FRT) capabilities. Indeed, a fault on the transmission grid could result in the sudden loss of a significant wind power that has to be balanced by primary reserves (as an example of such a contingency, an E.ON 2005 wind report [3.12] reported the sudden loss of 1100 MW of wind due to a single two-phase fault).

of fluctuations is based on time series of wind power and load calculation (10 minutes or one hour average).

Probability density functions of load and net load variations can usually be described by a gaussian law. To manage 99.7 % of potential fluctuations, an additional amount of tertiary reserves ΔQ is therefore required:

$\Delta Q = 3 * (\sigma_{NL} - \sigma_L)$, where σ_{NL} and σ_L are the standard deviation of net load and load (if the error in available production can be neglected)

If wind power and load are not correlated, the standard deviation of net load is:

$\sigma_{NL} = \sqrt{\sigma_L^2 + \sigma_W^2}$, where σ_W is the standard deviations of wind power

Then (Q is the amount of tertiary reserves without wind generation):

$$\Delta Q = 3 * \left(\sqrt{\sigma_L^2 + \sigma_W^2} - \sigma_L\right) \text{ and } Q = 3 * \sigma_L$$

$$\frac{\Delta Q}{Q} = 3 * \left(\sqrt{1 + \frac{\sigma_W^2}{\sigma_L^2}} - 1\right)$$

The amount of additional reserves depends on the ratio between wind power and load standard deviation, which demonstrates the simultaneous effect of penetration rate, geographical dispersion and forecast accuracy (i.e.: value of σ_W).

3.5.4 Impact on tertiary reserve requirements in some power systems

3.5.4.1 Case study of Minnesota

Within the MISO (Midwest Independent System Operator) area, the State of Minnesota is willing to develop its renewable portfolio (cf. [3.16]). In the considered scenarios, wind penetration may reach levels from 15 % to 25 % of the peak load in 2020, with 20 000 MW of peak load. A study was therefore performed to evaluate the impact of wind power on reserve requirements at different time scales.

Regulating Reserve

Regulating reserve provides compensation for system imbalances over very short periods of time (seconds to minutes). This service is provided by units with the necessary response rate operating on Automatic Generation Control (AGC). According to operators from MISO, the relationship shown in Fig. 3.17 may be derived.

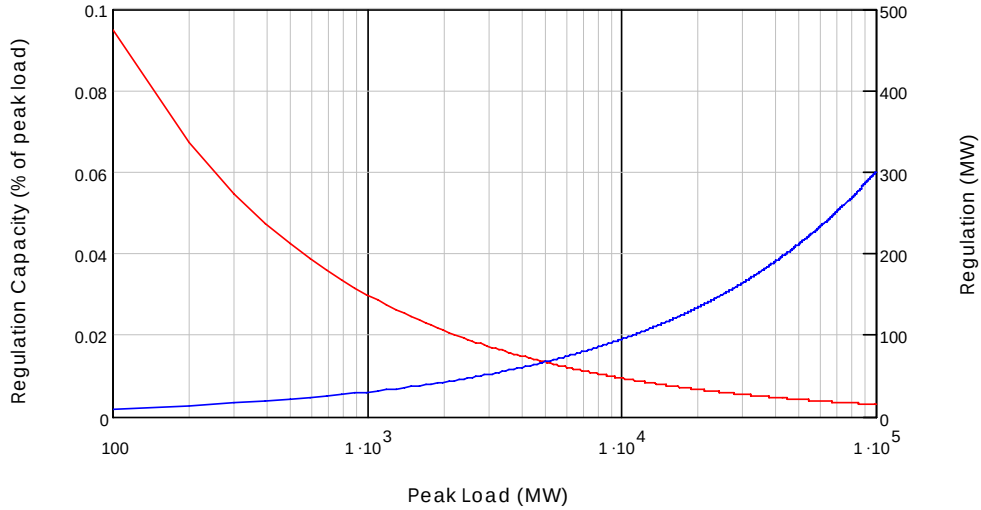


Fig. 3.17: Approximate Regulating Requirements for a Balancing Authority as a Function of Peak Demand

Although the regulation capacity decreases as a percent of peak load, the actual MW required increases. Based on the NREL analysis of the regulation time frame characteristic of 2 MW for a 100 turbine wind plant, the regulation requirement for the Minnesota balancing area is shown in Table 3.5. A slight increase due to wind power penetration may be observed.

Table 3.5: Estimated Regulation Requirement for MN Balancing Authority in 2020

Scenario	Regulation Capacity Requirement
Base	137 MW
15% Wind Generation	149 MW
20% Wind Generation	153 MW
25% Wind Generation	157 MW

Contingency Reserve

The single largest contingency in the Generation Reserve Sharing Pool, of which the Minnesota balancing area is a part, is the loss of a 500 kV line to Manitoba with imports of 1500 MW. This remains the single largest contingency for the study period, so the Minnesota share of 660 MW for this contingency, 330 MW spinning and 330 MW non-spinning (quick-start), remained unchanged. Further consolidation into the Midwest Contingency Reserve Sharing Group is expected to further reduce this obligation.

Load Following Reserve

Within the hour, once the regulation service has been provided, additional flexibility is required to follow the slower trends in the net load shape from hour to hour. This flexibility is provided through the 5-minute market. Additional flexibility is required in the market as additional wind generation is installed. This additional flexibility was determined based on a

statistical analysis of the 5-minute changes in the net load. The standard deviation of these changes is shown in Table 3.6.

Table 3.6: Summary of Five Minute Variability

Scenario	Standard Deviation of 5-minute changes
Base	50 MW
15% Wind Generation	55 MW
20% Wind Generation	57 MW
25% Wind Generation	62 MW

Two standard deviations encompass over 95 % of all variations, which was deemed sufficient.

Operating Reserve Margin

Due to the favourable impact of a large wind plant distributed over a significant geographical footprint, the major variability and uncertainty associated with the wind plant output is moved into time frames from one to several hours ahead. A persistence forecast is a good approximation for the forecasting method expected to be used for this time frame. Table 3.7 shows the next-hour standard deviation from a persistence forecast for the three wind generation scenarios.

Table 3.7: Next Hour Deviation from Persistence Forecast by Wind Generation Scenario (Fehler! Verweisquelle konnte nicht gefunden werden.**)**

Scenario	Standard Deviation of 1-hour Wind Generation Change
15% Wind Generation	155 MW
20% Wind Generation	204 MW
25% Wind Generation	269 MW

In the study, additional hourly reserves of twice the standard deviation, referred to as operating reserve margin, were conservatively decided in order to accommodate the unpredicted hourly changes in the wind generation.

Total Operating Reserve

Based upon the above considerations, a table of Total Operating Reserves (Table 3.8) can be constructed. This table summarizes the additional reserves carried due to the variability and uncertainty of the wind plant output as described above, given in MW and in % of balancing area peak load.

Table 3.8: Estimated Operating Reserve Requirement for Minnesota Balancing Authority with 20 000 MW load [3.16]

Reserve Category	Base		15% Wind		20% Wind		25% Wind	
	MW	%	MW	%	MW	%	MW	%
Regulating	137	0.65%	149	0.71%	153	0.73%	157	0.75%
Spinning	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Non-Spin	330	1.57%	330	1.57%	330	1.57%	330	1.57%
Load Following	100	0.48%	110	0.52%	114	0.54%	124	0.59%
Operating Reserve Margin	152	0.73%	310	1.48%	408	1.94%	538	2.56%
Total Operating Reserves	1049	5.00%	1229	5.86%	1335	6.36%	1479	7.05%

3.5.4.2 United Kingdom

A study of the needs of additional reserves is presented by [3.11]. This report presents the case of the UK in 2020. At a 30 minutes time horizon, the standard deviation of wind power is 1.4 % of the installed wind power, whereas the standard deviation of conventional load is about 340 MW. If a 10 GW wind park is considered:

$$\sigma_{NL} = \sqrt{340^2 + 140^2} = 368\ MW$$

$$\Delta Q = 3 * (368 - 340) = 84\ MW$$

$$\frac{\Delta Q}{Q} \approx \frac{84}{3 * 340}$$

According to this study, the integration of 10 GW of wind power would result in an increase by 8 % (with respect to the total amount of tertiary reserve) of the 30 min reserve in the UK.

3.5.4.3 Spain

As reported by [3.13], Spain already experienced fast fluctuations of wind power in the range of 1000 MW/h and must therefore adapt the amount of reserve to adjust such hourly variations. Based on statistical analysis of forecasts results made by REE, the additional margin is comprised between 400 and 650 MW considering a forecasted wind power of 2000 – 4000 MW with time horizon 20 – 40 hours.

3.5.4.4 Germany

The DENA study [3.14] assessed the requirements for reserve capacity due to large scale integration of wind. The performed statistic study took into account the probability functions of wind feed-in forecasts errors, load forecasts errors, and power plants outages. To manage 99.9975% of the potential fluctuations[9], 2000 MW of maximum[10] additional positive reserves would be required on a day-ahead basis considering 14.5 GW of installed capacity (in 2003).

[9] The study was performed with a considered admissible deficit level of 0.0025 %
[10] Depending on the wind generation forecasts

3.5.4.5 Nordic countries

The Nordel system covers four Nordic countries (Denmark, Sweden, Norway and Finland) and has a peak load of roughly 67 GW. The frequency control in normal operation has first the primary reserve (600 MW divided to the four countries in proportion of their yearly demand) that is automatic by using AGC of (mainly hydro) power plants. If the frequency is not kept in the normal operation limits by the instantaneous reserve bids from the TSO balancing market is used. These bids can be activated in 10-15 minutes. One of the TSOs will coordinate the frequency control, and bids are activated in the country that has the cheapest bids in the market. If there are bottlenecks between the countries, price areas for the balancing market are formed. In Nordel, reserves for disturbances (contingency reserve) are kept separately. The amount of that reserve is determined by the largest power loss in the system.

A study of wind power impacts on the reserve requirements of the Nordic power system may be found in [3.15]. This work considers a 4σ confidence level (level required to cover 99.99 % of all variations) to assess the need for additional reserves to manage hourly variations. The main impact of wind power will be seen in the 10-15 minute time scale operating reserve – this is actually coming from the balancing market in the Nordic countries. Three years of wind power production hourly data was gathered from the four Nordic countries to make two wind power scenarios: 1. distributed, same amount of installed capacity in all four countries and 2. concentrated, half of the wind power capacity in Denmark. Variability of this wind power production data was combined with synchronous load data to see the increase in the distribution of variations at a 4σ confidence level due to wind power. According to this study, wind power has a significant impact at 10 % penetration level (19 000 MW wind power). The increase in the amount of reserve requirement is 2 % of wind power installed capacity at this penetration level (or 310 – 420 MW depending on how concentrated the wind power is). At higher penetration rate of 20 %, 4 % are required (or 1200 – 1600 MW).

As a consequence, the amount of required additional reserves must be assessed on a case by case basis using country specific statistical data. The results of such studies are dependent on the considered country due to the set of specific parameters to be taken into account.

3.5.5 Conclusions

According to the performed studies and the experiences of considered countries, the impact of wind power on the tertiary reserve and margins can not be neglected, since significant hourly fluctuations of wind power and forecast errors have to be managed.

However, comparing these requirements within different countries may be highly complicated:

- Even though the same probabilistic method were used in several countries, the variety of considered admissible levels of risks may result in significant changes in reserve requirements (if standard deviation is considered: +/-3σ are required to guarantee a 99,7 % confidence level, whereas 95 % requires only +/-2σ)
- The power fluctuations heavily depend on wind regimes and geographical distribution of wind farms. The need for reserves may therefore be different even for countries with equivalent wind penetration rate
- The time horizon used for tertiary reserves assessment, which depends on the market rules of each country, is a key issue. With an extended time range, the standard deviation of forecast error will increase, and more reserves will be required

3.6 Wind generation control

Managing wind forecast errors

Controlling wind power injection may be a key issue due to the uncertainty of feed-in forecasts. As an example of difference between the actual and forecasted generation, a comparison of wind output forecast and actual output in Republic of Ireland on December 9th and 11th 2004 is reported by [3.17]. It can be seen on Fig. 3.18 that the sharp fall of output on 10 December (from 1am to 6 am) was predicted (although with 35% error), but the sharp rise on 10-11 December (from 10 pm to 5 am) was not expected. Therefore the power system operator had to unload high merit conventional units to balance the system.

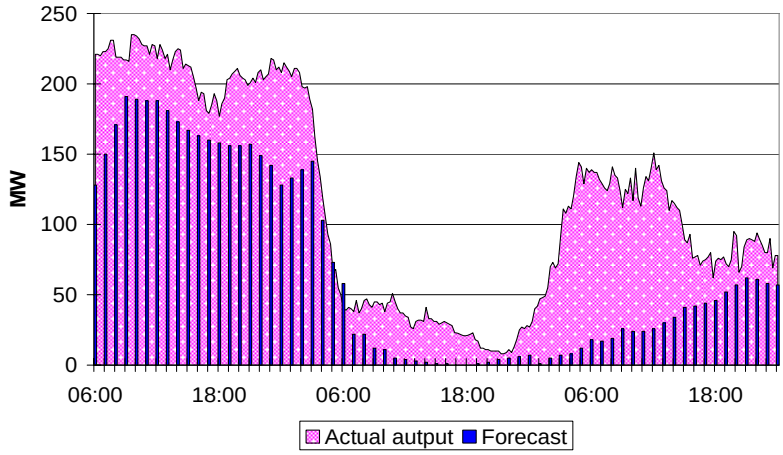


Fig. 3.18: Forecast and actual wind power output in the Republic of Ireland on 9-11 December 2004

To cope with these unexpected changes in wind power injection, it may be necessary to develop wind generation control systems, especially in case of power systems with high wind penetration. At present, such controls can take form of curtailment of wind generation.

Control criteria have to be put in place that are based on statistical wind generation data and the technical ability of power system to accommodate the amount of wind energy at specific system conditions. Criteria based on statistical data are presented in [3.18]**Fehler! Verweisquelle konnte nicht gefunden werden.**. They can be used in conjunction with limiting the wind power generation during periods preceding the morning load demand ramp, in order to avoid possible sharp drop of wind power output occurring while the load demand is increasing; or when sharp decrease in wind power output is forecasted during period of morning load rise to have units in place ready to meet this rise. At present 4 wind plants in the Republic of Ireland power system are able to provide curtailment services.

Reduction of grid constraints

Due to the strong increase in installed wind capacity, the power flows are significantly impacted, as described in section 1 of this report. The transmission grid may therefore be operated close to its limits in some areas.

In northern Germany for instance, the DENA study identified a need for grid extension in order to accommodate wind power as reported in [3.14].Since these extensions are long-time projects, wind power curtailment may be used to relieve grid constraints until then. Otherwise, additional wind farms connections would not be possible anymore.

An example of such a system is given by E.ON Netz in [3.19]. In order to avoid constraints on transmission grid, renewable energy feed-in may be temporarily reduced. In case of grid overload (e.g. high wind production), a reduction signal is sent to participating wind farms. Another signal is then sent when the grid constraint disappears in order to bring wind generation back to its original value. In the E.ON area, a 1100 MW installed wind capacity is contributing to this generation management.

Another example of wind power generation control due to grid constraints is given by [3.20] and [3.21]. Thanks to its wind generation forecast tools, the Spanish TSO REE is able to anticipate technical constraints due to wind power. For instance, during New Years' Day 2004, a risky situation was identified by TSO. The admissible wind generation was indeed 1500 MW, whereas 2000 MW of wind generation were forecasted. It was therefore necessary to require a 500 MW wind power curtailment. This could be achieved in real-time thanks to the control center of wind farm operators in coordination with the TSO control center.

3.7 References

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4 Voltage Stability

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4.1 General Discussion

Voltage stability refers to the ability of the power system to maintain voltages at all busbars within the operational ranges during normal operation as well as after being subjected to disturbances in the network [4.1], [4.2]. Sufficient reactive power support is the most important part for voltage control and voltage stability in a transmission and distribution network. As reactive power can not be transported over long distances, the reactive power has to be supplied where required. Wind generators can affect the reactive power supply and thus the voltage stability in a power system in different ways.

For studying the impact of high levels of wind generation on voltage stability of power system, the system modifications caused by high levels of wind power need to be analyzed first. Integrating high levels of wind generation into a power system means that during high wind hours conventional power plants are disconnected and replaced by wind-farms. Thus synchronous generators integrated into the high voltage level are disconnected and replaced by wind generators, which are usually connected to lower voltage levels in the networks or to grid connection points far from load centers.

Fig. 4.1 and Fig. 4.2 are showing the substitution of a considerable part of the overall generation by wind generators [4.3].

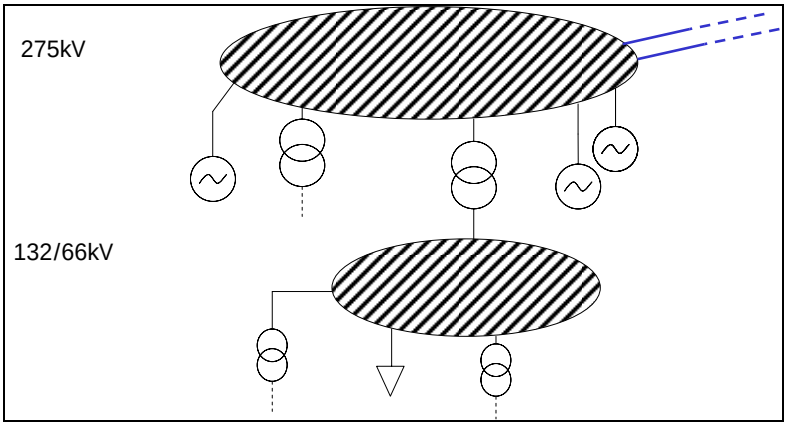

Fig. 4.1: Power system without wind power [4.3]

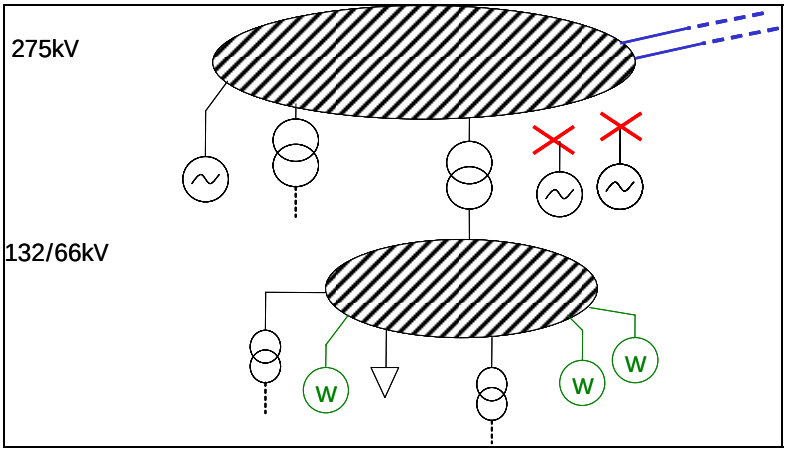

Fig. 4.2: Power system with high wind power penetration on the subtransmission or distribution level [4.3]

This substitution causes the following major differences between the system states:

- Generation is integrated into the subtransmission and often distribution network at lower voltage levels.
- Different generator technologies (DFIG, induction generators or converter driven synchronous generators instead of directly connected synchronous generators).
- Modified distances between the remaining synchronous generators.
- Different location of wind generation can result in increasing power transfer in the network.

The wind generator technologies behave differently from conventional synchronous generators with regard to:

- Transient voltage support due to reactive current during faults
- Steady-state reactive power/voltage regulation abilities

When replacing large synchronous generators connected to transmission level by small generators integrated into subtransmission or even distribution systems or far from load centre, the amount of reactive power reserve needed in the transmission grid is considerably reduced. In principle, modern wind generators are able to regulate the voltage and have a considerable reactive power range. However, most small distribution and subtransmission connected wind farms are operated at constant (and unity) power factor. Furthermore since wind farms are very often connected at weak points in the network, reactive power losses are considerable, which limits the possible contribution of wind generators to the reactive power balance at the transmission level. Thus, even wind generators with voltage regulation are not able to provide any substantial contribution to the reactive power balance at the transmission level.

Consequently, increasing amount of wind generation reduces reactive power reserves in the transmission system, which is defined by available reactive power of the synchronous generators, SVCs and shunt capacitors minus reactive power consumption in the network including reactive power of TCR and switchable inductors.

The different characteristics of wind generator as described above have an impact on voltage stability in the network. Two phenomena can be distinguished, which can be described as global effects on the network resulting in voltage collapse:

- Long-term voltage stability
- Short-term voltage stability

4.2 Effect of Wind Power on Long-Term Voltage Stability

Long-term voltage collapse typically occurs within several minutes. Immediately after a disturbance such as the loss of a large generator, voltage drops but also loads drop because of their voltage dependence. Step by step, the transformers feeding subtransmission networks and distribution networks start increasing the voltage at their secondary side by tap control actions. Consequently, active and reactive power loads increase again and can possibly drive the system into a voltage collapse, especially when reaching overexcitation limits of synchronous generators or when SVCs start saturating [4.2].

On the other hand, switchable shunts can help the system to maintain voltage stability. Therefore it is possible that in some cases, short-term voltage stability is the more critical issue, even if synchronous generators can provide much more reactive power in the short-term range because of thermal overloading capabilities.

Thus long-term voltage stability can be analysed by using "PV-curves" [4.2], i.e. by calculating a sequence of steady-state load-flow calculations versus varying load-levels in the network or increasing power transfer-levels into weakly connected network areas. Fig. 4.3 is showing an exemplary network configuration representing a power transfer over an interconnector into an area with wind generation connected.

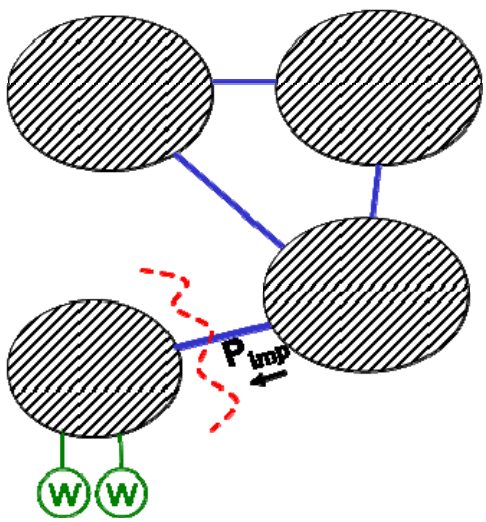

Fig. 4.3: Network configuration showing a power import into a network area with wind generation

The load-flow analysis considers the tap changers, over-/underexcitation limits using reactive power limits and switchable shunts. The long-term voltage stability limits have consequently to be analysed for several critical n-1 contingencies in the network, e.g. the loss of important lines or the loss of large power plants.

Fig. 4.4 shows PV curves for the healthy system (red) and for the loss of a large power plant (blue) for increasing power import [4.3]. It can be seen that to ensure stable operation, also after faults in the system, the power transfer across tie lines or the maximum load in a region has to be limited to the long-term voltage stability limit after the most critical contingency.

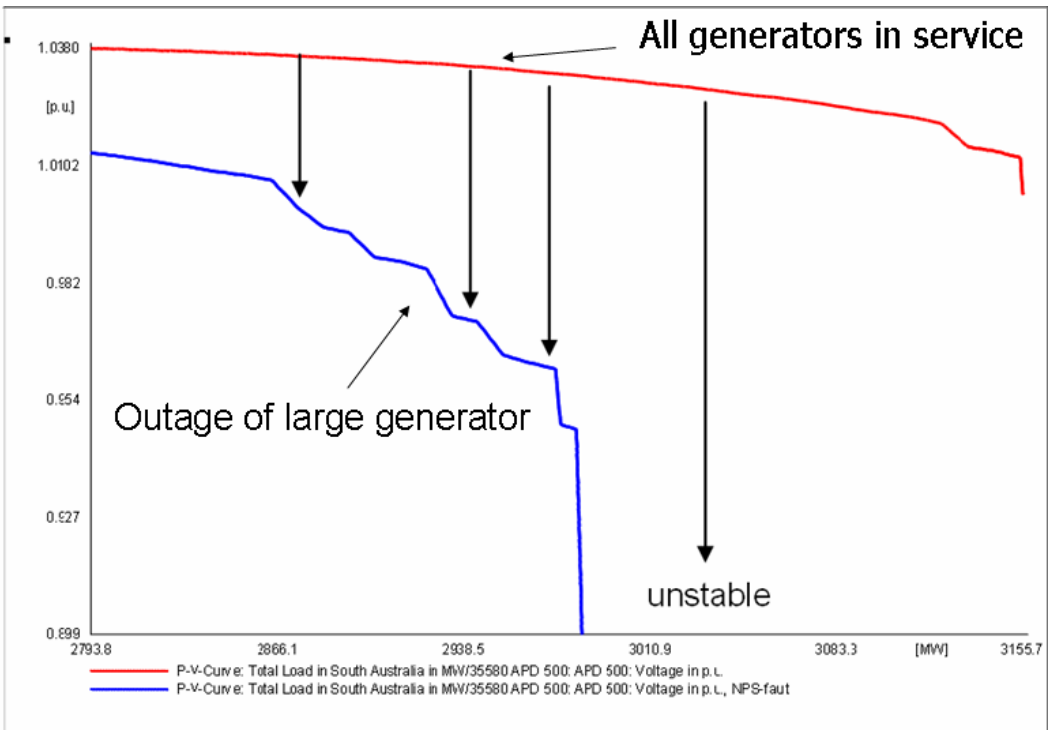

Fig. 4.4: Investigation of long-term voltage stability using PV curves in *PowerFactory* [4.3]

As explained above voltage collapse is a phenomenon that can be caused by a reactive power shortage in a certain location of the network only. This often is a highly loaded region or a highly loaded interconnector between two network areas. A voltage stability problem occurs if the reactive power supply in these sensitive regions is not sufficient anymore, i.e. nearby reactive power sources like SVCs or generators are hitting their limits.

As studies show the integration of large amounts of wind generation into a network reduces the reactive power supply and thus the voltage sensitive areas can be negatively affected. For example in a series of studies, commissioned by the Australian National Grid Operator NEMMCO and carried out by DIgSILENT, the impact of high levels of wind generation on the South Australian power transmission system has been assessed [4.4], [4.5]. In the study, the lowest transfer limit for an interconnector between two networks is determined for a variety of disturbances for different levels of wind power integrated in the system. The network configuration is similar to the one shown in Fig. 4.3.

Fig. 4.5 shows the impact of increasing wind generation on the stability limit.

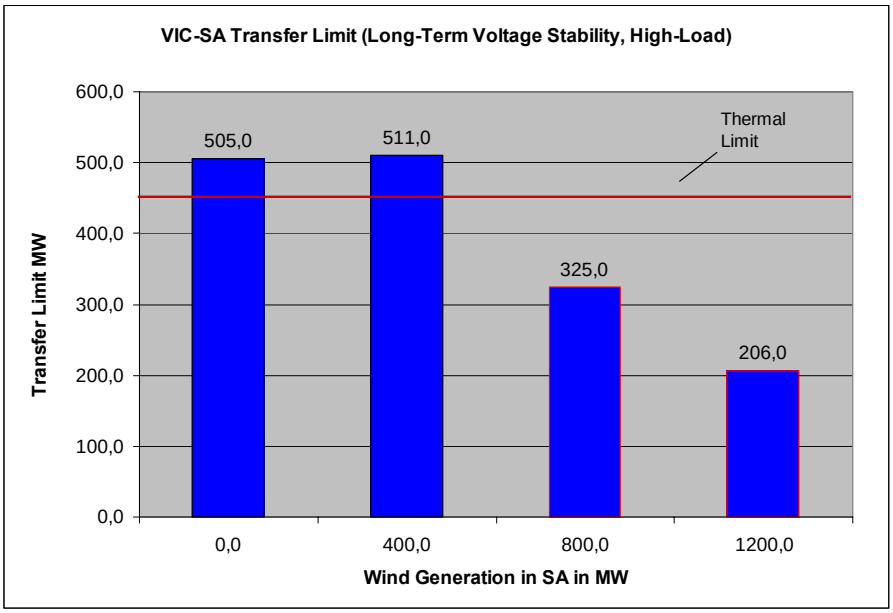

Fig. 4.5: Impact on Long-Term Voltage Stability Constrained Import Limits [4.5]

The study shows an important trend:

- The reactive power contribution of wind power plants is highly dependent on the technology used, the connection point and voltage level as well as additional reactive power support (SVC, STATCOM)
- The reactive power reserve in the network is reduced by an increasing substitution of conventional power plant by wind generators.
- There is a steady reduction of the long-term voltage stability limit resulting in a reduction of the maximum transfer along the interconnecting lines.

These effects are due to the steady depletion of reactive power reserves available to the transmission network. The displacement of scheduled generators mentioned above results in the removal of the static and dynamic reactive support provided by those generators. Reactive power reserves and the ability of the system to regulate the voltage are reduced because of the limited ability of generators embedded in sub-transmission systems to provide reactive power for supporting the voltage at the transmission level.

To counteract against the reduced reactive power reserve, several measures can be taken:

- Including additional reactive power sources, like switchable capacitor banks, SVCs, STATCOMs, synchronous condensers, etc.
- Increasing the number of “must run” units for conventional power plants.
- Location of large wind plants with dynamic reactive power control on the transmission system.

4.3 Effect of wind power on short-term voltage stability

In contrast to long-term voltage stability issues, which could let the system run into a voltage collapse in a time range of several minutes, short-term voltage stability problems can occur if the static stability limit of the network is exceeded within a time frame of a few seconds after a disturbance, such as the loss of a large generator. Thus the stability limits are analysed by transient simulations, where the system behaviour has to be investigated for various critical contingencies in the system.
Reactive power reserves are of minor importance in the short-term range because the excitation of synchronous generators has considerable thermal overload capabilities in the time frame of a few seconds and can hence provide more reactive power than in the time frame of several minutes. However, SVCs have the same reactive power limits in the short term as in the long term and are very important for maintaining short-term stability. Additionally switchable capacitor banks cannot support the system in the short-term range because switching times of capacitor banks are usually too long. Besides the impact on dynamic reactive reserves the impact of wind generation on short-term voltage stability limits is related to the active power support of wind power plants during low voltages.

Fig. 4.6 shows the distribution of short-term voltage stability limits for the most critical contingency and different wind generation levels for the example of the Australian network [4.4], [4.5]. The network configuration is similar to the one shown in Fig. 4.3. It can be seen that there is a trend towards lower import limits with increasing amount of wind generation in South Australia, although the short-term voltage stability limit always remains above the long-term limit. It can thus be concluded, that the short-term voltage stability is not as critical as the long-term limits.

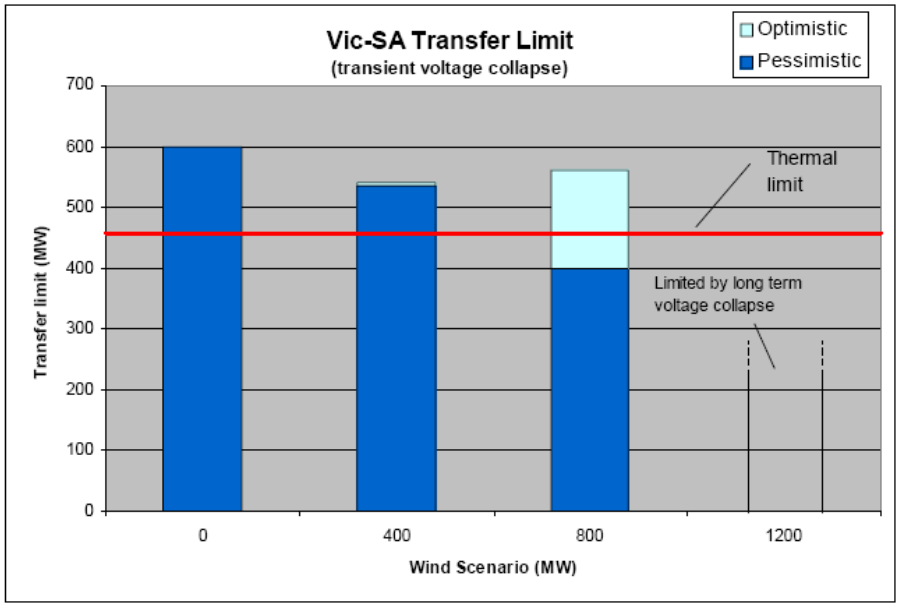

Fig. 4.6: Impact on short-term voltage stability constrained import limits (high-load case)

In the study different low-voltage ride-through behaviour of the wind generators have also been analysed. The behaviour has been characterised by a "pessimistic" behaviour - no low voltage ride-through (LVRT) - and trip of the wind farm at voltages below 0.8 pu and "optimistic" behaviour (LVRT control). The results especially highlight the relevance of low voltage ride-through capability of all wind power plants under all voltage variations that can occur, if the system is operated close to voltage stability limits. LVRT capability has now been recognized as an important requirement in most grid codes around the world.

4.4 References

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5 Transient Stability

Contributors: Holger Mueller, Markus Poeller, David Jacobson

5.1 General Discussion

The growing importance of wind power, which can be observed in many European countries, the USA, Canada and also Australia [5.1] requires detailed analysis of the impact of wind power on power system stability. Therefore, a number of studies have been carried out recently and are currently carried out for identifying required network reinforcement, reserve requirements and the impact of wind power on power system stability (e.g. [5.2]).
These studies are dealing with different aspects related to wind power, such as the fluctuating nature of wind power, location of wind resources, various generator technologies and generator control. The results are generally representing a superposition of various wind power aspects and predict required network reinforcements, additional reserve requirements, the impact on power system stability etc. but it is difficult to explain the reasons for encountered problems and required system upgrades from these studies because of the large variety of aspects that have been studied simultaneously.
In this chapter the phenomenon of large-disturbance (transient) rotor angle stability is described. Additionally the low-voltage ride-through (LVRT) or fault ride-through capability of the different wind generator technologies is shown and compared.
In a first step, the question "why is wind power different?" needs to be answered. The main aspects having a possible impact on transient stability issues are:

- Wind resources are usually at different locations than conventional power stations. Hence, power flows are considerable different in the presence of a high amount of wind power and power systems are typically not optimized for wind power transport. This aspect can be more or less severe in different countries. In Germany, where most wind resources can be found in the north, this aspect is extremely important [5.2].

- Wind generators are usually connected to lower voltage levels than conventional power stations. Most wind farms are connected to subtransmission (e.g. 132kV, 110kV, 66kV) or even to distribution levels (e.g. 20kV, 10kV) and not directly to transmission levels (>132kV) via big step-up transformers as in case of conventional power stations.

- Wind generators are usually based on different generator technologies than conventional synchronous generators. Modern variable speed generators are usually equipped with low-voltage ride-through capability. Where the grid code does not require LVRT also wind generators which will trip at more severe faults are often installed.

Based on these differences two phenomena can be distinguished and analysed, which can be affected by wind generation:

- Global effects which can result in loss of synchronism of generators:
    - Transient stability (large-disturbance effect)
- Local effects
    - Trip of wind generators after subjected to a disturbance often called low-voltage ride through (LVRT)

5.2 Effect of Wind Power on Transient Stability

Transient stability is defined as the ability of the power system to maintain synchronism after severe disturbances, for example short circuits or generator trips [3]. It is also described with the term large-disturbance rotor angle stability. Hence this stability phenomenon is analysing the behaviour of the synchronous generators in a power system, if they are able to maintain synchronism with the other synchronous generators during and after disturbances.

The behaviour of the system is highly dependent on type and duration of disturbance, thus to ensure transient stability in a system often a number of critical contingencies have to be simulated at different locations. For evaluating transient stability, the following two indices are used [5.3], depending on the case:

- **CCT:** The critical fault clearing time (CCT) is calculated for all cases. The CCT represents a useful measure for characterizing the transient stability performance of a given dispatch scenario.
- **Critical Area Exchange:** This value determines the maximum export from one to another area at which the system is not becoming unstable for a specified fault, e.g. a three-phase fault with a fault clearing time of 150ms.

The different aspects of large amount of wind power influencing transient stability are analysed and discussed separately from each other in [5.4].
Fig. 5.1 is showing an exemplary network configuration representing a power transfer over an interconnector to an area with large amounts of wind generation connected.

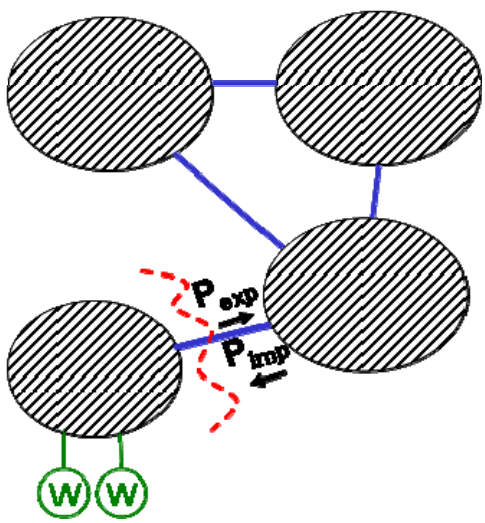

Fig. 5.1: Results of low voltage ride-through test.

The different effects of wind power generation onto the network behaviour can be distinguished and compared to the basic setup as discussed above in section 5.1:

- Changing location of generation and thus modifying the power flow in the network.
- Using a different generator technology.
- Connection of wind generation at lower voltage level rather than on the transmission level.

Compared to the scenario without wind generation, different impacts on transient stability are analysed. It can be concluded that the effects of wind power on transient stability are [5.4], [5.5]:

- Re-location of generation increases tie-line flows, especially when high wind resources are located in one particular area, which can have a negative impact on transient stability.
- Lower level of kinetic energy increase during fault due to less synchronous generation in the network, that increases transient stability export limits and improves voltage recovery.
- Larger voltage dip during fault and reduced dynamic power reserve in case of no fast voltage control of wind generators and connection to subtransmission levels.
- Increase of average distance between synchronous generators leading to higher transfer impedances due to disconnection of conventional power plants during high wind scenarios.

As an example, in a series of studies, commissioned by the Australian National Grid Operator NEMMCO and carried out by DIgSILENT, the impact of high levels of wind generation on the South Australian power transmission system has been assessed. The results are summarized in [5.6], [5.7].

The transient stability of the system has been analysed by transient simulation with the power system analysis tool *PowerFactory*. As shown in Fig. 5.2, the effect of wind generation tends to have a beneficial influence on transient stability constrained export limits. This is primarily due to the decoupling between the mechanical components of the generator and the network resulting in a reduced increase of kinetic energy stored in the remaining synchronous generators at fault clearance [5.7]. Hence the overall impact of wind generation onto transient stability in a transmission system can be assumed to be relatively small [5.6].

Generally, it can be concluded that different aspects of wind generation lead to a different type of transient stability impact. In actual cases, there will always be a superposition of the above mentioned aspects, including a variety of generator types and voltage levels to which wind generators are connected. So there is no general statement possible, if wind generation improves transient stability margins or if the impact is rather negative. The answer depends on system properties, location of wind resources and generator technologies and the problem has to be analyzed individually for each case.

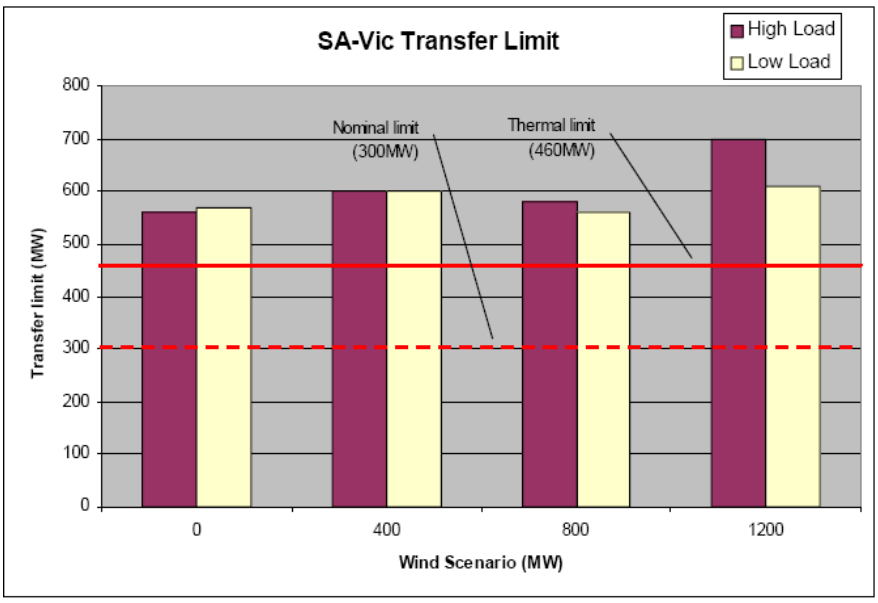

Fig. 5.2: South Australian export transient stability limit.

5.3 Low Voltage Ride-Through Capability (LVRT)

The grid code of most countries requires wind generators to stay connected in the case of network faults (Low voltage ride-through capability (LVRT) or fault ride through capability (FRT). It is of particular importance to transmission system operators, that wind farms stay connected in case of faults at major transmission levels leading to a voltage depression in a wide area, which could lead to a major loss of wind generation if wind farms were not equipped with LVRT-capability (see also chapter 4 "Voltage Stability"). Therefore, LVRT-capability is a definite requirement for all larger wind farms in most countries.

In this section the performances of the three most common types of variable speed wind turbines are shown: a directly grid-coupled induction generator, a doubly-fed induction generator and a full converter synchronous or asynchronous generator. Additionally the analysis of a new type of wind generator technology, the directly coupled synchronous generator with hydro-dynamically controlled gearbox has been analyzed and the results are summarized in this chapter.

5.3.1 Directly Grid-Coupled Induction Generator

The directly grid-coupled induction generator takes more careful interconnection planning in order not to adversely impact transient stability. Modern versions of these generators are sufficient in terms of low-voltage ride-through capability.

A directly grid-coupled induction generator typically comes equipped with power factor correction capacitors to bring the power factor to unity, which is not enough to meet the Manitoba Hydro connection requirements of 0.95 leading to lagging. To overcome this issue, the first approach is to assume that the remaining leading reactive power support can be supplied by switched capacitor banks, typically located on the intermediate voltage bus. The transformer between the intermediate and high voltage systems is supplied with an on-load tap changer (OLTC), which is set to control the steady-state intermediate voltage and thus keep the generators operating within their steady-state voltage limits. The OLTC setpoint and deadband play an important role in preventing tripping of the generators due to undervoltage or overvoltage [5.10]. Transient stability studies may indicate that mechanically switched capacitors are not adequate and a dynamic supply of reactive power is needed.

One issue that can arise with the directly-grid coupled induction generators is mechanical oscillations when recovering from a fault if the grid is weak. Depending on the strength of the remaining system following the fault clearing and the size of wind plant, the mechanical oscillations can be fairly large and sometimes unstable. A general observation is that if the short circuit ratio (SCR) (i.e. MW/MVAsc) of the remaining system after the fault has cleared is greater than approximately 10%, the directly grid-coupled induction generators will produce fairly large mechanical oscillations. The oscillations affect also system voltage which can be enough to violate transient undervoltage criteria and sometimes cause the wind plants to trip out due to overvoltage. These voltage oscillations can be aggravated if there are shunt capacitors connected to the intermediate bus.

Wind speed input to the turbines was also observed to impact the damping of mechanical oscillations; the higher the wind speed for the same power output, the less damped the oscillations [5.10].

Figure 5.3 demonstrates the transient response for a 200 MW and 300 MW wind plant that are recovering from a normal-clearing solid three-phase fault (3PF) with SCRs of approximately 8% and 12.5%, respectively. The response of the 300 MW wind plant with the SCR of 12.5% is unstable.

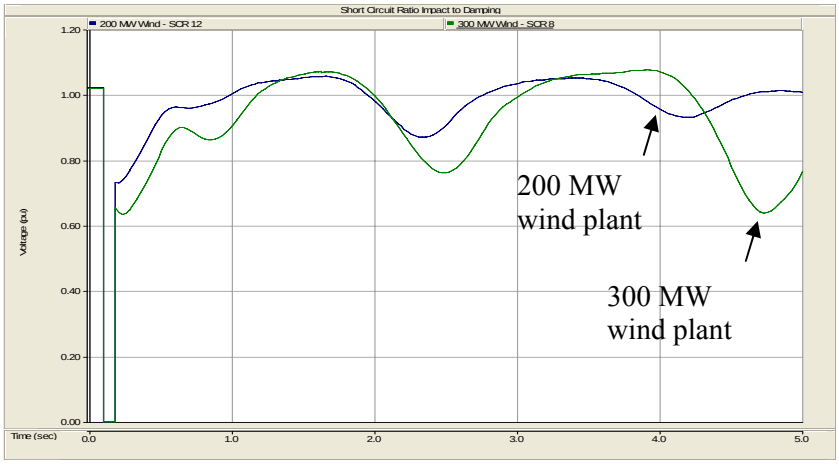

Fig. 5.3: 230 kV voltage. 200 MW and 300 MW wind plants. Normal clearing 3PF.

The possible mitigation for the mechanical oscillations depends on the disturbance. If it is a NERC Category C (n-2) disturbance, such as a breaker failure scenario, it may be acceptable to crosstrip the wind plant, assuming no other adverse system impacts are created due to the generator crosstrip. If it is a NERC Category B (n-1) disturbance, then further stability studies are undertaken to replace some or all of the switched capacitors with dynamic reactive power support, such as an SVC or a STATCOM, in order to bring the voltage oscillations and damping within acceptable criteria.

If induction generators (with additional 34.5 kV switched capacitors, 4x10 MVAr per 100 MW of wind generation) are installed, for most buses a wind farm size of approximately 100-150 MW is the maximum that can be connected, although the LVRT behaviour of each wind farm should be studied prior to its connection especially if it operates according to the local grid code without some form of additional dynamic VAR support. The stability issues that arise with a larger wind farm are violation of the 0.7 pu post-disturbance undervoltage criteria, as well as undamped voltage oscillations which eventually turn into voltage collapse.

5.3.2 Doubly-Fed Induction Generator

A doubly-fed induction generator (DFIG) has been found to have little impact on the transient stability performance of the system. It provides sufficient reactive power support and voltage control to meet grid code requirements, like the Manitoba Hydro connection requirements [5.13]. Overvoltage ride-through (up to 1.2pu rated voltage) has not been an issue due to the fast voltage control capability of these generators. In some instances, DFIG have been observed to aid in locally reducing the worst case system overvoltages, thereby providing slight improvement to the system. The only issue that has surfaced with the DFIG is the fault ride-through capability during a local, solid three-phase fault. Depending on the length of transmission line and impedance of transformer between the generator and the fault, the voltage at the low-voltage generator bus can sometimes dip slightly below the ride-though capability. In these instances, it is recommended to supply a transformer with a slightly higher impedance to ensure the wind farm will not trip out during the fault.

5.3.3 Full-Converter Synchronous/Asynchronous Generator

A synchronous or asynchronous generator which is connected to the system using a full voltage source converter has even less impact on the transient stability performance of the system than the DFIG. According to the converter's fast control of active and reactive power

or of the AC voltage at generator terminals directly, it is possible to provide reactive power to the network during steady-state as well as dynamically during disturbances. Thus no additional reactive compensation equipment is usually needed.

The converter controls can be equipped with additional LVRT controls and reactive current boosting during faults. Thus sufficient reactive power support and voltage control can be provided to meet grid code requirements. Overvoltage ride-through (up to 1.2pu rated voltage) has not been an issue due to the fast voltage control capability of these generators.

5.3.4 Directly Coupled Synchronous Generator and Hydro-Dynamically Controlled Gearbox

This type of wind generator technology can not easily be compared to the other generator technologies, as its behaviour is similar to conventional power plants. The main issue of synchronous generators with direct grid connection (without power electronics converters) concerning LVRT capability is their ability to remain in synchronism during and after major voltage sags. The corresponding effect is also named 'transient stability'.

The main parameters influencing transient stability are:

- Rotor inertia/turbine power during the fault.
- Depth of the voltage sag.
- Duration of the voltage sag.
- Short circuit impedance of the grid to which the generators are connected.

In a study of the behaviour of this generator type, the response of a wind farm to various faults for different short-circuit ratios has been analysed [5.11].

Fig. 5.4 shows simulation results of a solid three-phase fault with 150 ms duration at high wind conditions for a strong network [5.11]. The figures show the voltage at the PCC as well as the voltage at the generator terminals and generator speed.

The results show, that the generators do not face instability when the wind farm is connected to a sufficiently strong network in relation to the total rated wind farm power. Also at low or medium wind conditions, i.e. at a low loading of the generators, no unstable behaviour was shown. Only in the case of an extremely low short circuit level and full load operation, transient stability can be a problem. Transient stability can further be supported using the ability of the hydro-dynamic control of the WinDrive® to reduce mechanical torque during grid faults.

During the fault, the synchronous generator supports the voltage by large reactive currents, which are much higher than reactive current support that can be achieved by other wind generator concepts. The voltage supporting properties might even allow other wind farms in the area to better ride through network faults.

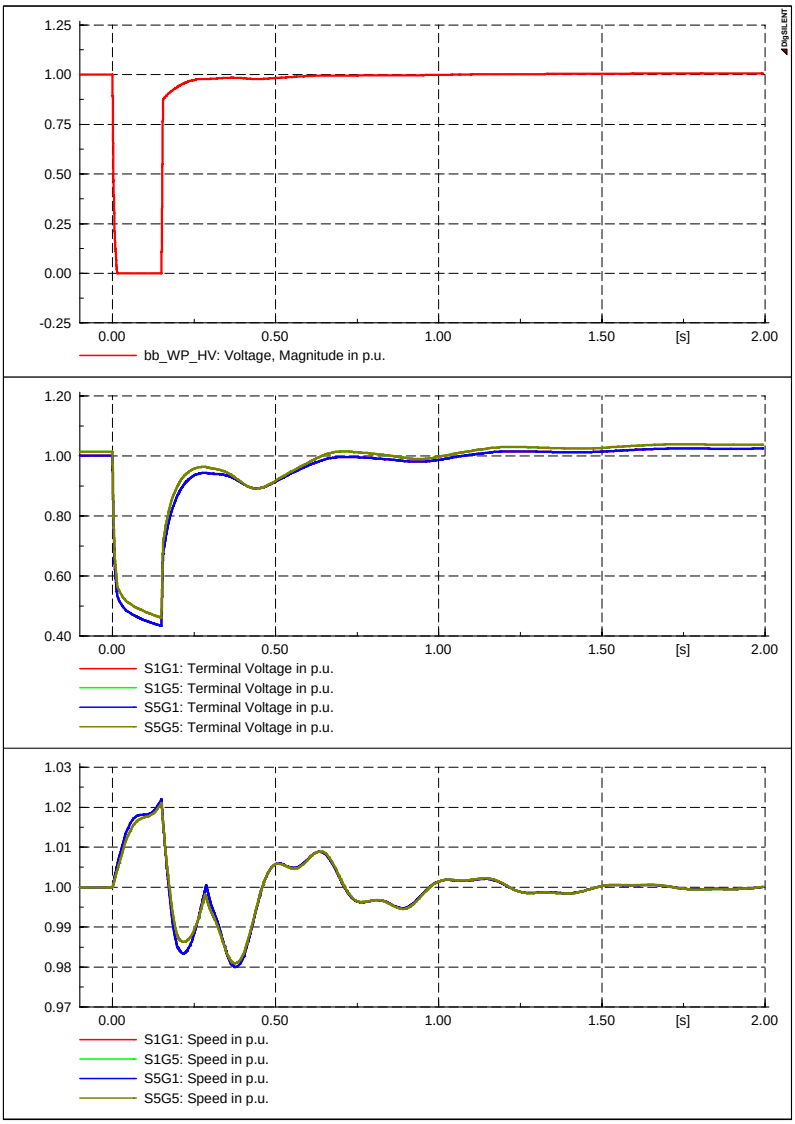

Fig. 5.4: Voltages at the PCC, at the generators and the generator speeds during a solid three-phase fault for 150 ms at high wind conditions [5.11].

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6 Reactive Power Control and Voltage Control Capability

Contributors: Holger Mueller, David Jacobson, Jérôme Duval

6.1 General Discussion

In principle, modern wind generators are able to regulate the voltage and have a considerable reactive power range. However, most wind farms are operated at constant (and unity) power factor. Furthermore since wind farms are very often connected at weak points in the network, reactive power losses are considerable, which limits the possible contribution of wind generators to the reactive power balance at the transmission level. Thus, even wind generators with voltage regulation are not able to provide any substantial contribution to the reactive power balance at the transmission level.

The following major differences describe the behaviour of wind generators compared to conventional synchronous generator technology:

- Different generator technologies (DFIG, induction generators or converter driven synchronous generators instead of directly connected synchronous generators).
- Transient voltage support due to reactive current during faults
- Steady-state reactive power/voltage regulation abilities

This chapter describes the reactive power supply capabilities of wind generation during steady-state conditions and after disturbances. For improving reactive power and voltage control additional equipment like FACTS is often used at the generators or at the point of common coupling. The last section gives a brief overview about the requirements of existing grid codes regarding the reactive power output.

6.2 Reactive Power Output Capability

In France, wind power plants are mainly connected on distribution networks, due to the former purchase obligation which only applied to wind farms below 12 MW. Nevertheless, the new regulation broadens purchase obligation to more powerful units located in so-called "wind development areas".

Due to the resistance of lines in distribution networks (with a high R/X ratio, unlike transmission network), active power injection induces a significant voltage-rise effect, especially on weak grids. Reactive power and voltage control are therefore a key issues for integrating wind power into LV and MV network.

To cope with these voltage issues, the Distribution Network Operator (DNO) of countries with significant distributed generations (DG) defined requirements on reactive power capacities of wind power plants. Theses requirements may vary depending on the country.

- In Germany (Distribution Code 2003, VDN [6.10]) ancillary services are not expected from wind turbines in the MV/LV distribution system. Generators are required to work in a range of cosφ defined at planning stage

- In Denmark (Technical regulation TF 3.2.6 [6.11]), reactive power is expected to be in a control band (which varies with wind farm active power output, e.g. tanφ comprised between 0 and +0.1 at rated power). The reactive power capacities available outside this band must be stated before connection. It shall be made available to the DNO for the system's needs.
- In the UK, the DNO may ask voltage regulation to some generating units
- In Spain, incentives are given to so-called "special regime" generating units if they make their reactive power vary depending on the load (peak, valley… cf. [6.12])
- In France, the DNO has defined connection requirements [6.13] on reactive power capacities of generation plants in MV distribution grid. These depend on the type and size of the considered unit:

Installed power of the WF	**Connection conditions regarding voltage control and reactive power**
$P \leq 1$ MW	$0 \leq Q \leq 0.4\ S_n$
1 MW $< P \leq$ 10 MW	$-0.1\ S_n \leq Q \leq 0.5\ S_n$
10 MW $< P \leq$ 12 MW	$-0.2\ S_n \leq Q \leq 0.6\ S_n$
Induction generators (whatever the rated power is)	$0 \leq Q \leq 0.4\ S_n$

Different control modes may be required by the French DNO. Nevertheless, the constant power factor mode is chosen most of the time.

But to deal with the risk of overvoltages on the distribution network, voltage control may have to be implemented on wind farms. DGs (and among them wind farms) are thus expected to use voltage control mode in the future.

6.3 Available technologies

Squirrel-cage induction generators do not have voltage control capacities, since its reactive power absorption is linked to the active power production, the rotor speed and the voltage value at the generator stator. The required reactive power is produced by capacitor banks. Therefore, this technology of fixed-speed turbines is not well suited for voltage control unless it is associated with additional devices such as compensating capacitors or FACTS.

Unlike fixed speed turbines, variable speed technologies (doubly-fed induction generators and synchronous or induction generators connected through full power converters) offer the opportunity to control reactive power either in production or in absorption. The reactive power capabilities (either in absorption or in production) depend on the power electronics converters rating. Usual control range may be ± 0.3 Sn.

Additional compensation systems can improve generators reactive power and voltage regulation capacities. Furthermore, some devices are now able to propose so-called "zero power" voltage regulation, as described by [6.14]. This is a solution for the reactive power control even when wind turbines are not generating active power.

In order to comply with the reactive power operation requirements of the wind farms, there are a number of wind generator technologies and power compensation devices available that can be used in combination [6.12].

6.4 Voltage regulation test for wind generators connected to the distribution network

To assess the performance of a voltage regulation, a field test campaign was performed on a distribution connected wind farm, on request of the DNO EDF Réseau de Distribution. This wind farm is made of synchronous generators connected to a 20 kV grid.

The implemented voltage regulation limits the voltage rise effect induced by wind generator power injection. The wind generator is therefore expected to absorb a varying amount of reactive power depending on the voltage at the point of common coupling (PCC). The phase angle is therefore 0° for voltage lower than a reference value. Then, reactive power increases with respect to voltage, and remains constant when maximum absorption value is reached.

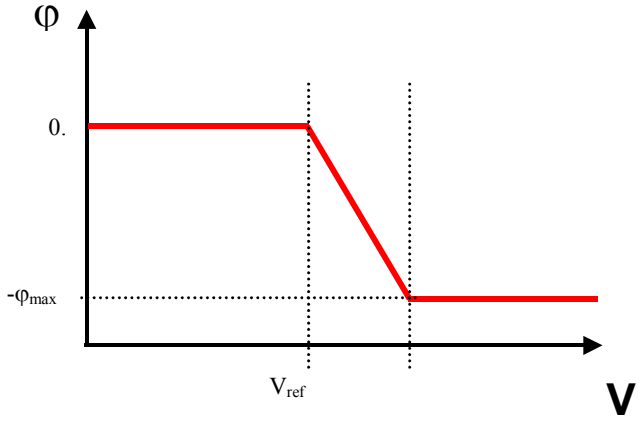


Fig. 6.1: φ(V) control

As expected, the tested regulation resulted in a better behaviour of wind generators. Above reference voltage value, reactive power absorption is increased as a response to voltage increase.

6.5 Dynamic Reactive Power Support

To either ensure low-voltage ride through of the wind generators, to prevent voltage collapse near the point of common coupling of the wind farm or to help comply with the connection code by providing reactive power during faults, additional components are often used at or near wind farm connection point.

In an exemplary investigation of a wind park connection, a reasonably-sized SVC is able to mitigate the undamped voltage oscillations and prevent voltage collapse. However it does not prevent the violation of a certain voltage limit (here 0.7 pu) immediately following fault recovery once the wind plant size becomes too large. This is at least partially due to the fact that the voltage is quite low and the SVC can only produce a reduced VAR output during low voltage.

A STATCOM provides extra benefit for the post-disturbance undervoltage criteria, however it does not damp out the oscillations as well as a similar sized SVC. A model representing a ±8 MVAr STATCOM was tested and was found to provide superior results when compared to a SVC. With a wind farm of 300 MW connected, six MVAr STATCOMs were needed to just meet the transient undervoltage requirement for a nearby three-phase fault. A similar sized SVC does not meet the undervoltage criteria, however it provides better damping.

It is possible that if the SVC controls were modified or optimized that the performance immediately following fault recovery could be improved. Figure 6.2 below shows a comparison of a 300 MW of wind farm with a 50 MVAr SVC, +/-48 MVAr STATCOM and with no dynamic VAR device, for a normal clearing three-phase fault.

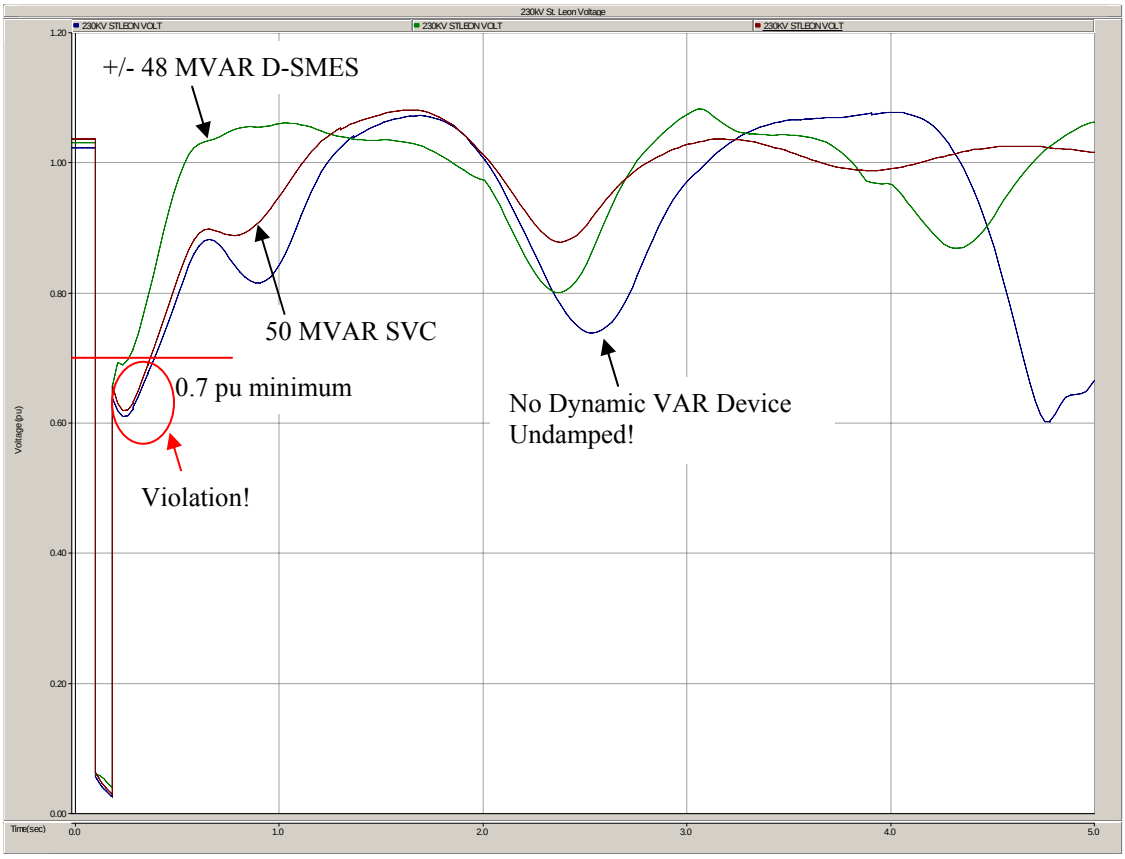


Fig. 6.2: 230 kV Voltage. 300 MW wind generation, Comparison of dynamic VAR support.

Alternately, a synchronous condenser would mitigate these issues as it would increase the short-circuit power at the bus. However, synchronous condensers are expensive and require maintenance.

6.6 Grid Code Requirements for Wind Power Plants

6.6.1 International Grid Code Requirements

Several recent papers provide a review of international grid code requirements for wind power plants, as well as the impact of grid code requirements on wind turbine design [6.15], [6.16]. As an illustration of these requirements, the grid codes of several different countries are described below, at both the transmission and distribution levels.

6.6.1.1 GB Reactive Power Requirements for Wind Farms

There is planned to be a large penetration of wind energy in the UK which is mainly driven by the UK government's targets of 10% of electrical energy generated from renewable resources by 2010, 15% by 2015, with aspirations of 20% by 2020 [6.2]. Electricity generated from renewable sources now accounts for around 3% of the UK's supply [3], where wind energy is expected to be the most significant renewable energy resource.

The situation in the UK regarding wind energy integration can be divided in two scenarios:

- High penetration of small amounts of generation connected to distribution networks (distributed generation or embedded generation). Generally wind farms of less than 100 MW, connected to 11 kV or 33 kV networks. [6.1]

- Large amount of generation connected to the transmission network. Generally wind farms in the range of 100 MW and 1000 MW, connected to 275 kV or 400 kV networks. [6.1]

Depending on the point of connection of the wind farm, there will be specific requirements that wind farms are required to comply to. This includes reactive power operation requirements, which is the purpose of this section.

GB Distribution Codes

There is a single Distribution Code for Great Britain. The Distribution Code specifies standards for the design and operation of Distribution Network Operator (DNO) owned distribution networks. To meet these standards, DNOs need to be notified about the connection of large loads and generator installations to their networks. The Distribution Code therefore requires users of distribution networks, such as electricity consumers and generators, to provide certain information about new loads and generator installations. It also specifies arrangements for the design of connections to DNO networks, and certain requirements for the control and protection of distributed generators. These requirements are contained in sections of Distribution, Planning and Connection DPC5, DPC6 and DPC7 of the Code [6.4].

GB Grid Code

The GB Grid Code for systems in England, Wales and Scotland is published by National Grid, which includes the requirements for the connection of generators in PC.A.3, PC.A.5 and CC.6.3. The GB Grid Code contains specific standards for wind farm connections. Although distributed generators are not directly connected to transmission systems, their operation can have a significant effect on the operation of these systems. For this reason, transmission system operators need to be informed about the connection of large distributed generation plants to DNO networks, which are in turn connected to their transmission systems. The Grid Codes specify requirements for the provision of information regarding such generator installations, as well as certain requirements for the performance, control and protection of these generators [6.5].

ScottishPower and Scottish and Southern Energy each control separate parts of the Scottish grid system. The GB Grid Code contains special conditions for both areas. In some cases a transmission system operator (TSO) can offer transmission connected wind farms a 33 kV point of connection thus reducing requirements of the wind farm power system design.

Distribution Code Reactive Capability Requirements

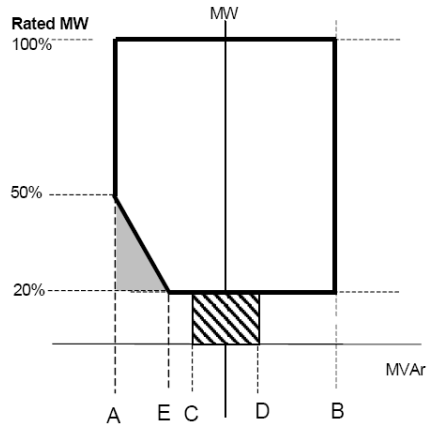
As well as generating real electrical power, generation schemes often generate or consume reactive power. This must be taken into account in the design of the connection scheme, as transfers of reactive power will contribute to the total current in the connection.

It is general practice for a DNO to ask a distributed generator to operate at or near to unity power factor, that is with minimum reactive power import or export, in order to maximise the real power capability of the network, however, there may be cases, given the network capacity, where it is desirable for the generator to import or export reactive power in order to assist network voltage regulation. [6.7]

Grid Code Reactive Capability Requirements

The reactive capability limits applicable to wind farm, documented in the current Grid Code for England and Wales produced by National Grid [6.5], are shown in the following points:

- Figure 6.3 is a diagram of the leading and lagging MVAr requirements for 100%, 50% and 20% of rated MW output at the point of connection.
- The Reactive Power output under steady state conditions should be fully available within the voltage range ±5% at the point of connection.



Point A is equivalent (in MVAr) to: 0.95 leading **Power Factor** at **Rated MW** output
Point B is equivalent (in MVAr) to: 0.95 lagging **Power Factor** at **Rated MW** output
Point C is equivalent (in MVAr) to: -5% of **Rated MW** output
Point D is equivalent (in MVAr) to: +5% of **Rated MW** output
Point E is equivalent (in MVAr) to: -12% of **Rated MW** output

Fig. 6.3: Power Factor and Reactive Power Requirement for Generating Units as required by the current Grid Code [6.5]

6.6.1.2 Ireland Reactive Power Requirement for Wind Farms

In Ireland, wind farms shall be capable of operating at any point within the power factor ranges illustrated in Figure 6.4, as measured at the lower voltage side of the grid-connected transformer. For wind farms where the connection point is remote from the grid-connected transformer, any supplementary reactive power compensation required to offset the reactive power demand of the HV line, or cable, between the connection point and the wind farm shall be identified during the TSO's connection offer process [6.4].

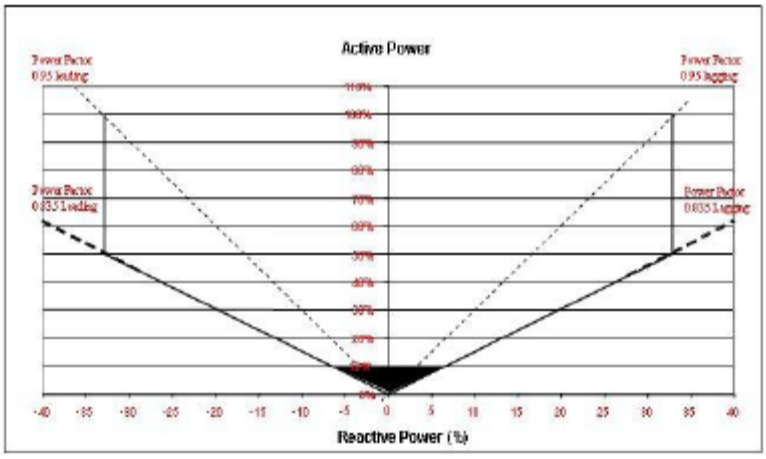


Fig. 6.4a: Reactive Power Capability of Wind Farms

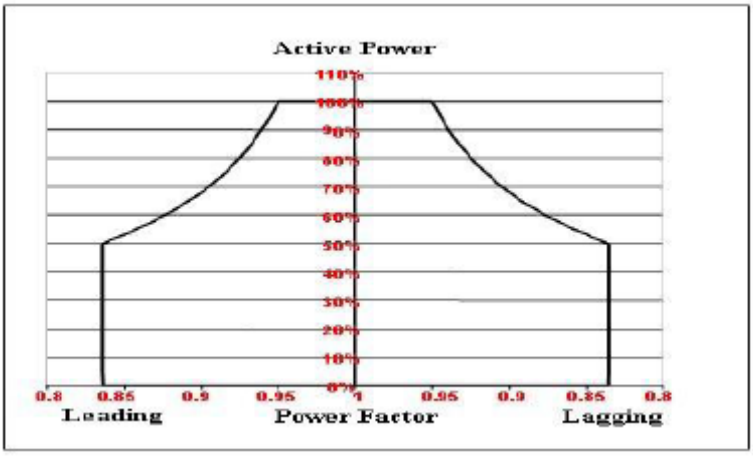


Fig.6.4b: Reactive Power Capability of Wind Farms

For operation below 10 % of the Wind Farm's MEC, the wind farm shall operate within the shaded triangle in Figure 4a. However, if this cannot be achieved, then the total charging of the wind farm network during low load operation (below 10%) shall be examined during the TSO's connection offer process. If during this examination it is identified that this charging may cause the voltage on the transmission system to be outside the transmission system voltage ranges, then the reactive power requirements will need to be altered.

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7 Influence of Wind Energy on Conventional Generation Plants

7.1 Efficiency and CO_2 emissions

Contributors: P. Souto, K. Voorspools, W. D'haeseleer

7.1.1 Introduction

Wind power is an intermittent, fluctuating, partly unpredictable and non-dispatchable power source. For the conventional part of the power system, wind power can be interpreted - apart from the actual power input - as an increased uncertainty in power deliverability by introducing an additional need for reserve to cope with the power fluctuations. This chapter deals with the implementation of wind power generation in broader power generation models. Special attention is paid to a detailed analysis of both the power generation of wind energy conversion and the operation of the central power system.

7.1.2 Wind power in power generation models

7.1.2.1 Simulation approaches

There are two main approaches that are commonly used for the simulation of wind power in broader power-generation models.

A first approach simulates wind energy conversion systems (WECS) as a fluctuating power source. The power-output profile of the WECS can be based on actual measurements or on simulated plausible profiles. The simulation of the operation of the rest of the system in cooperation with the WECS is often performed by using a ''negative-load'' approach. This means that the fluctuating power generation from the wind turbines is interpreted as generation that no longer needs to be provided by the ''conventional'' part of the power system. In practice, this is achieved by mathematically subtracting the power-generation profile of the wind turbines from the overall demand. In doing so, the fluctuating nature of wind power and the adjusted optimal use of the power system are fully accounted for. This approach is only useful when using a detailed power simulation tool in which the nuances of the wind power fluctuations are compatible with the resolution of the model. An example of such a model is PROMIX (Voorspools and D'haeseleer, 2000) in which the operation of a power system, subject to an hourly power demand, is simulated. A brief discussion of PROMIX and the use of PROMIX in this context are presented in Section 7.1.2.2.

Many simulation tools, however, lack the flexibility to implement such fluctuations in power demand and generation. Models, such as ENPEP (Jusko et al., 1996), use the load duration instead of the chronological demand profile. Other models, such as MARKAL (Fishbone et al., 1983) use strongly simplified demand profiles. Therefore, in the context of these models, detailed modelling of the WECS power generation is not useful or possible and it is often simulated as a constant reduced power output, respecting the annual electric energy output. E.g. if a 1000 MW wind farm has a capacity factor of 30% (or 2630 equivalent full-load hours per year), it is simulated at a constant output of 300 MW. Many power-generation simulations implicitly use the second method. This means that the power from wind turbines is averaged

over the entire year. However, it is our understanding that the validity of such simplifications or assumptions has not yet been verified in detail. Therefore, this study confronts both approaches.

7.1.2.2 Methodology for the simulation of wind power generation as part of a larger power system

The power-system simulation tool PROMIX

PROMIX simulates the response of a power system subject to a power demand. The power system used in PROMIX consists of different separate power plants. The operation of a particular plant is modelled as shown in Fig. 7.1. A plant is divided into separate parts of constant marginal energy use. The first part of the plant is defined as the minimum-operation point, below which it is not operated. When the minimum-operation point is reached, the dispatcher - or in this case the model PROMIX - has to decide whether the plant is to be shut down or further operated at its minimum-operation point while further modulating with other units. A plant can be operated at every level between the minimum-operation point and full load. Apart from the minimum-operation point, PROMIX also considers other technical restrictions of power plants such as the minimum up time and the minimum down time of a plant. Also, the fuels that can be used in the plant are specified. If different fuels are possible, PROMIX selects the most economic option.

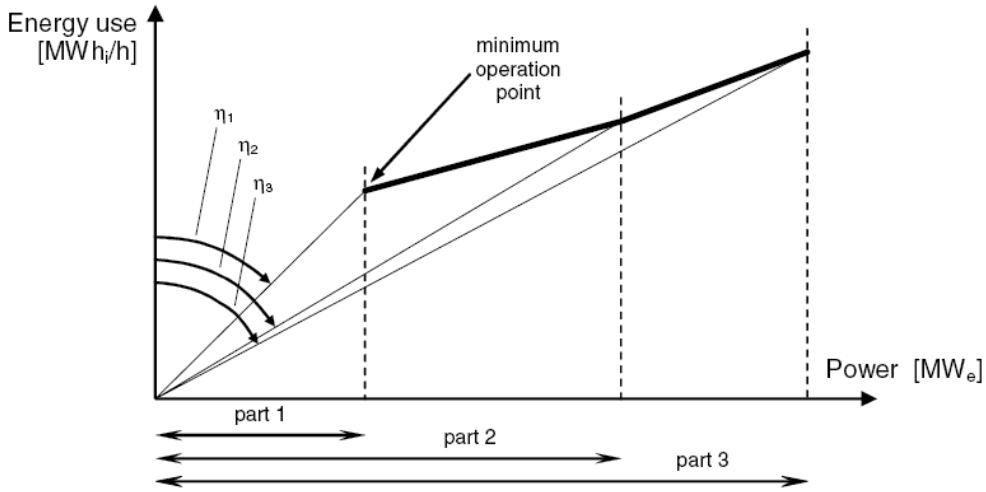

Fig.7.1: Operation of a power plant as used in PROMIX. A plant is divided in different parts of constant marginal energy use.

The fuel properties in PROMIX are the emissions and the prices. The fuel prices are further on used to optimally dispatch the power generation to the demand. The IEA prognoses (IEA, 2004) for the fuel prices for 2010 are used: steam coal at 40 $ per metric ton, natural gas at 3.3 $/MBtu and crude oil at 22 $/barrel. Expressed in $/GJ, these numbers correspond to 1.43 $/GJ for steam coal, 3.1 $/GJ for natural gas and 3.8 $/GJ for crude oil. For nuclear ‘‘fuel’’ we assume a price of 1.09 $/GJ. [11]

The power demand is given on an hourly basis. Since PROMIX is intended to be used on a system level, the possible cross-border interactions need to be implemented exogenously. It is

[11] Meanwhile the fuel prices have literally exploded, e.g. mid 2008 the price for crude oil was already above $130 per barrel. As the other energy prices will follow, the results will not change significantly.

assumed that the necessary new investments in the power system from now until 2010 are all combined- cycle gas-fired units.

PROMIX simulates the most economic dispatching of the power system on an hourly basis, while respecting the technological restrictions of the individual power plants (e.g. minimum-operation point, minimum up time, minimum down time, output-related primary-energy use according to the plant characteristic of Fig. 7.1). The output of PROMIX consists of the power generation of the separate power plants on an hourly basis as well as the corresponding energy use, primary-energy costs and emissions. For a more elaborate discussion of PROMIX and some application examples, refer to Voorspools and D'haeseleer (2000).

PROMIX and the impact assessment of WECS

In this chapter, the power generation of WECS is evaluated by using a scenario approach with PROMIX simulations. In one scenario, the base case, no additional WECS are installed. In an alternative scenario, additional WECS are considered. The impact of the power generation of the WECS is evaluated by comparing both scenarios. In order to evaluate the impact of the fluctuations of wind power, the variations in annual overall CO_2 emissions in comparison to the base case where no additional wind power is installed, are used as a diagnostic.

In order to illustrate our methodology with concrete examples, in this chapter, an estimate for the Belgian power system of 2010 is used. In general, this is a 15 GW system consisting of 38% nuclear power, 26% combined-cycle gas, 20% steam-cycle power (gas, coal, oil, blast-furnace gas, coke-oven gas) and 8% cogeneration. This is only the rough outline of the system. In total, there are over 200 different power units in the PROMIX input, all with their own specificities.

7.1.3 Case studies; simulation of wind power in Belgium

7.1.3.1 Wind-power-output profiles

In concrete case studies, different power-output profiles have been considered for four different locations (Fig. 7.2): onshore Vlissingen, near shore Middelkerke, inland Melsbroek and deep inland Kleine Brogel.

Fig. 7.2: Map of Belgium with the indication of four locations of wind-speed measurements.

For these locations, wind-speed measurements are available at 10 m height. WECS with a 50 m tower are assumed. Therefore, the wind speeds are first converted from 10 m height to 50 m by using the following formula (Grubb and Meyer, 1993):

$$v_{h_2} = V_{h_1} \frac{\ln(h_2/z_0)}{\ln(h_1/z_0)},$$

with v_h the wind speed at height h and z_0 the roughness length. It is assumed the turbines to be built in open terrain with a roughness length z_0 of 0.03 m (Grubb and Meyer, 1993). Also, h_1 is 10 m at which the measurements are available and h_2 is 50 m at tower height.

To convert the wind-speed profile to a power output profile, the power-output characteristic shown in Fig. 7.3 is used. This curve is based on the power curves of the VESTAS V52-850 kW turbine (brochure download possible at www.vestas.com).

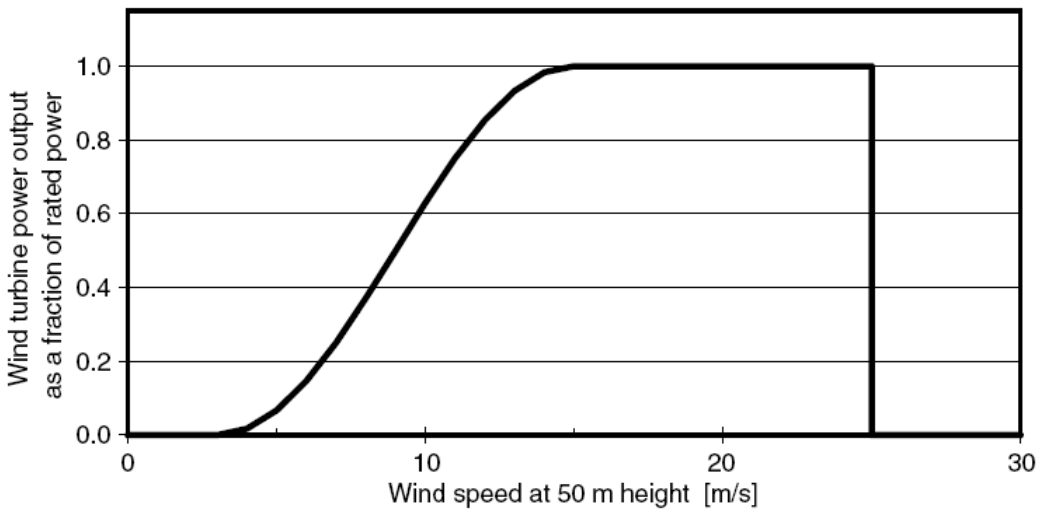

Fig. 7.3: Wind-turbine power output as a function of the wind speed at 50 m height (based on the data for the VESTAS V52-850 kW turbine).

The resulting normalised power output profiles for the four locations are partly shown in Fig. 7.4 for Vlissingen, Fig. 7.5 for Middelkerke, Fig. 7.6 for Melsbroek and Fig. 7.7 for Kleine Brogel. The output profiles are shown for three entire weeks: week 1, week 11 and week 25 of the same year for all four locations. The WECS in Vlissingen, Middelkerke, Melsbroek and Kleine Brogel have a capacity factor of 43%, 29%, 20% and 12%, respectively. Apart from these four individual power profiles, also a ‘‘mixed’’ profile is used in which the sum of an equal amount of installed power at the four locations is considered. The resulting output profile is shown in Fig. 7.8. The capacity factor for this mixed profile is 26%. Note that this combined profile fluctuates less than the individual profiles.

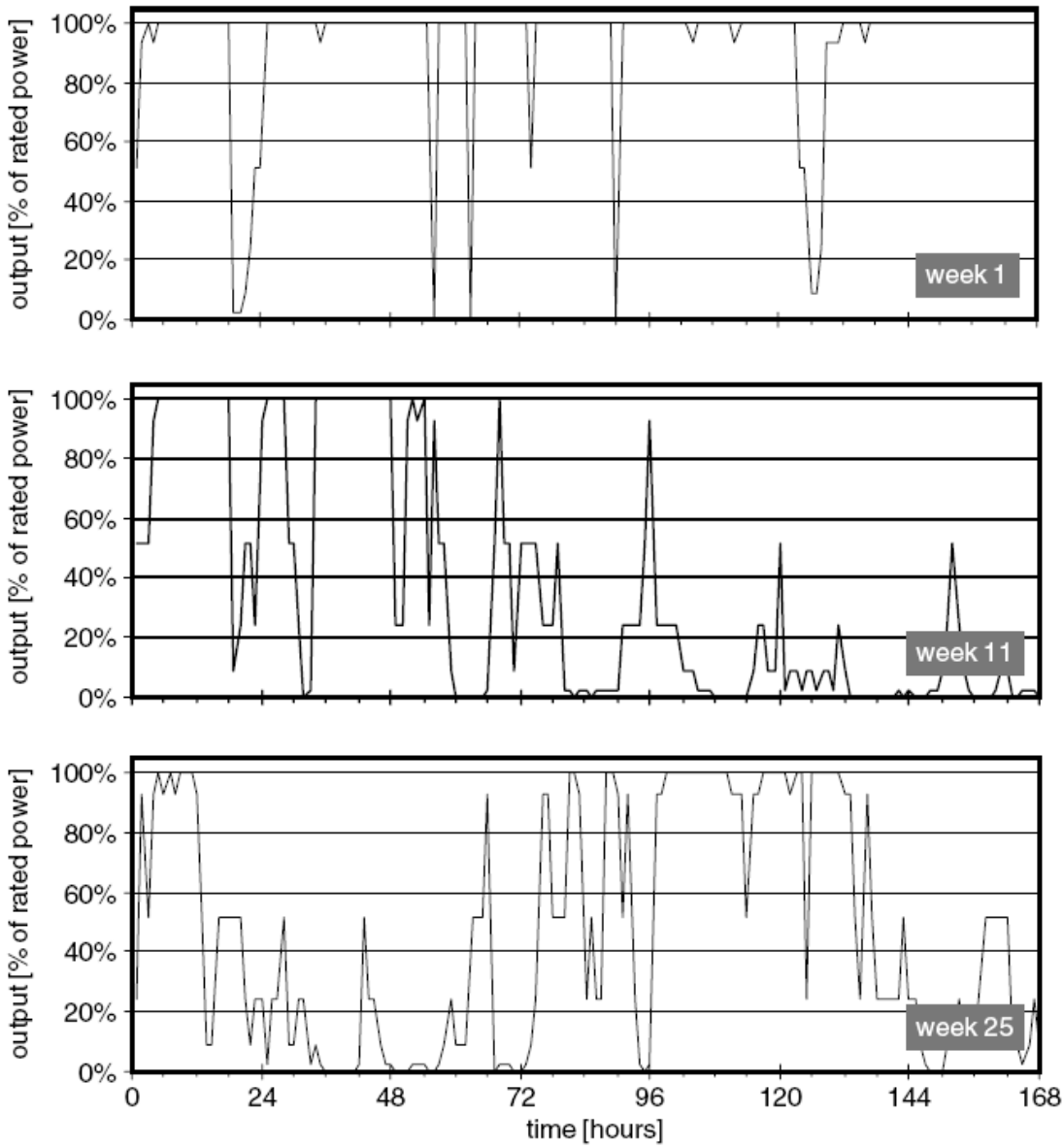

Fig. 7.4: Normalised fluctuating generation profile for wind turbines in Vlissingen (coast) with overall annual capacity factor of nearly 43%. The profiles for weeks 1, 11 and 25 are shown.

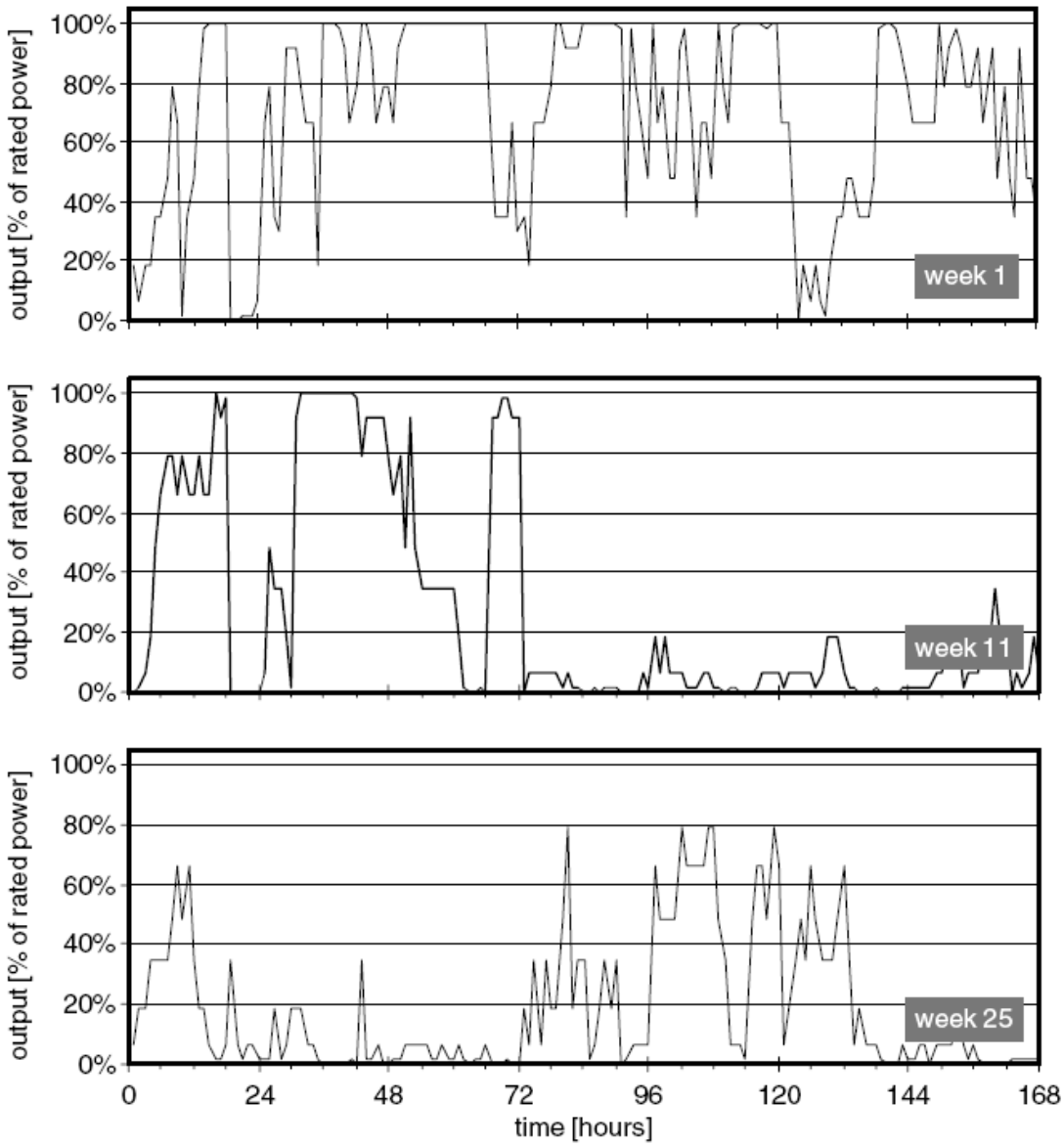

Fig. 7.5: Normalised fluctuating generation profile for wind turbines in Middelkerke (near cost) with overall annual capacity factor of nearly 29%. The profiles for weeks 1, 11 and 25 are shown.

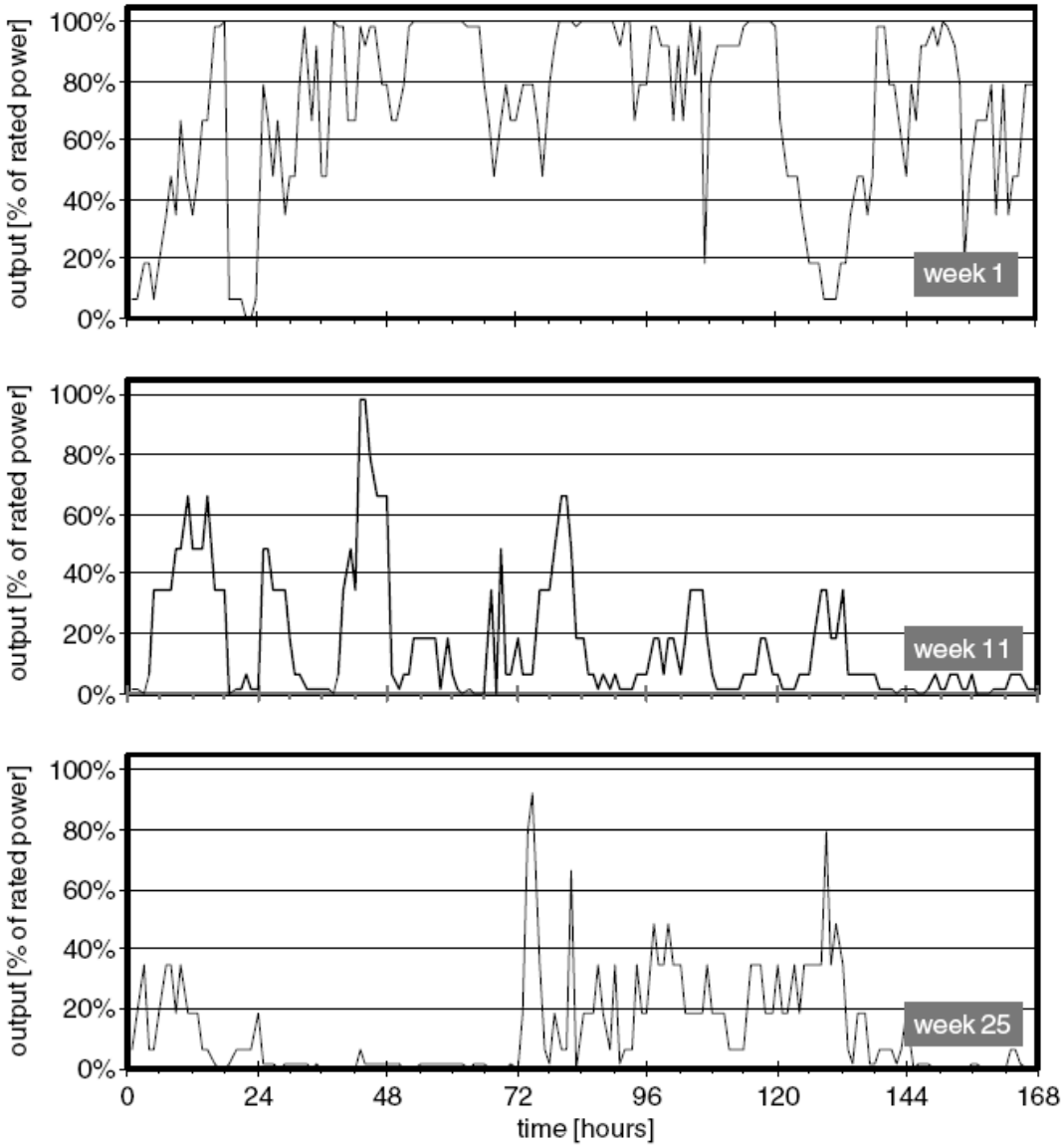

Fig. 7.6: Normalised fluctuating generation profile for wind turbines in Melsbroek (inland) with overall annual capacity factor of 20%. The profiles for weeks 1, 11 and 25 are shown.

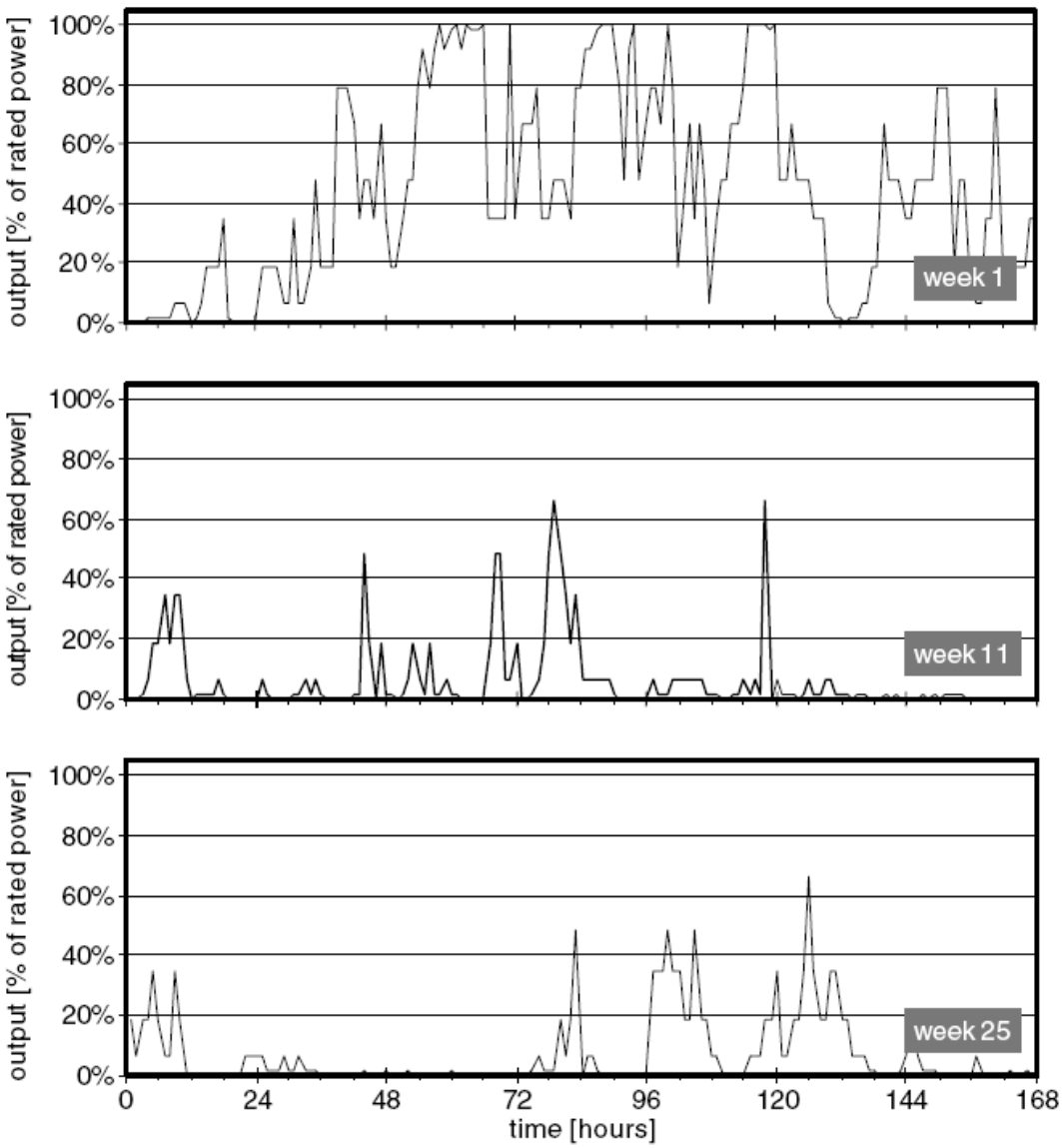

Fig. 7.7: Normalised fluctuating generation profile for wind turbines in Kleine Brogel (deep inland) with overall annual capacity factor of 12%. The profiles for weeks 1, 11 and 25 are shown.

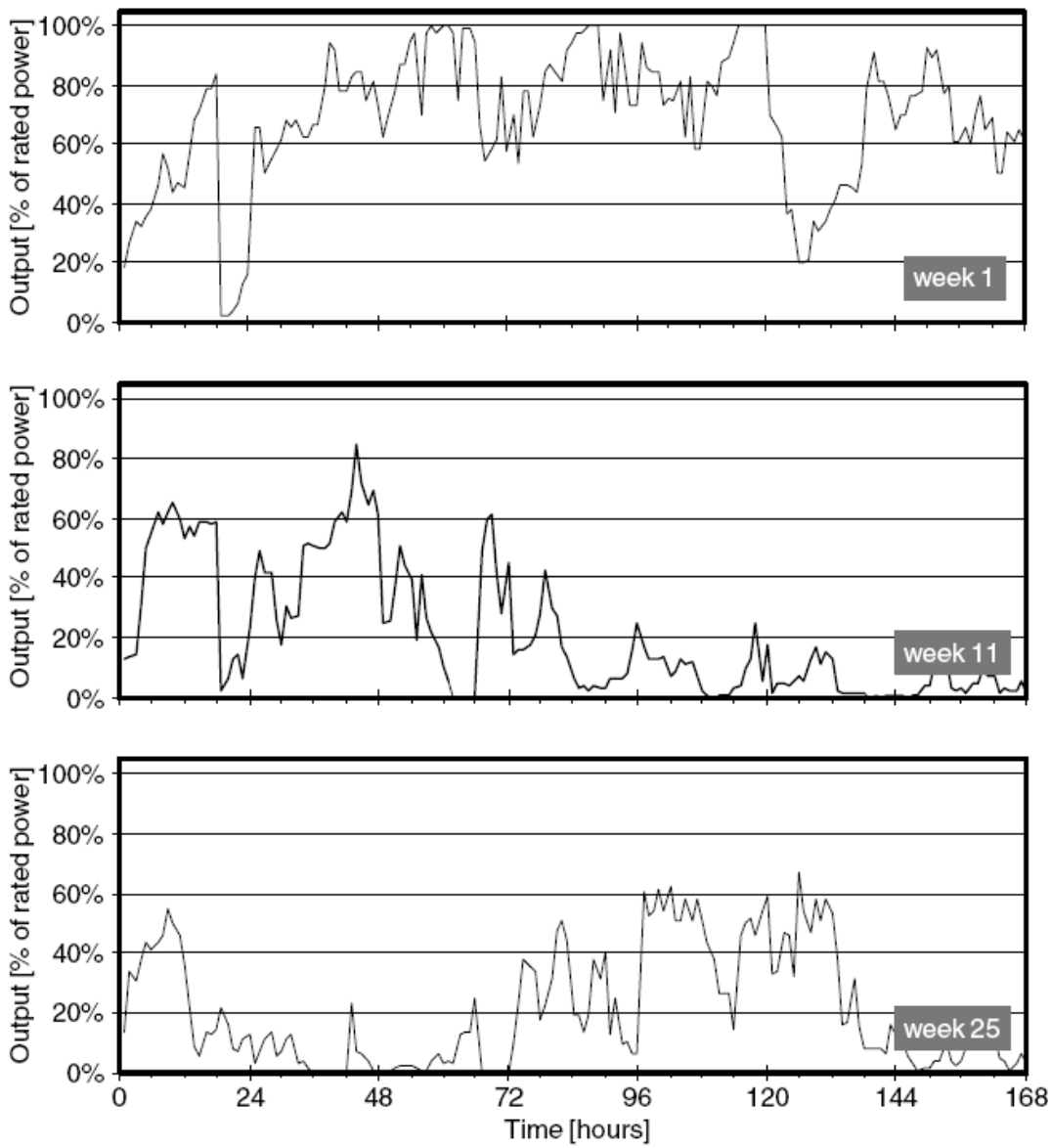

Fig. 7.8: Combined normalised fluctuating generation profile for equal amounts of wind turbines in Vlissingen, Middelkerke, Melsbroek and Kleine Brogel with an overall annual capacity factor of nearly 26%. The profiles for weeks 1, 11 and 25 are shown.

7.1.3.2 Different case studies

Base case without additional WECS

Before discussing the results of the scenarios with additional WECS, the results for the base-case scenario without additional WECS are presented, because the results of the ''alternative'' scenarios are all compared to this base case. In the base case, for an annual electricity demand in Belgium in 2010 of 98.4 TWh/a, an electricity generation of 95.3 TWh/a is calculated with a primary- energy use of 820 PJ/a and corresponding GHG emissions of 28.0 Mton CO_2eq.

The largest contributions in the power-generation mix come from nuclear plants, 42.6 TWh, combined-cycle gas-fired units, 30.6 TWh, cogeneration, 12.30 TWh and coal-fired power stations, 4.95 TWh. The remaining 4.85 TWh comes from blast-furnace and coke-oven gas (mostly in combination with other fuels in a conventional plant), gas-fired (single-cycle) power units, oil-fired power units, waste, hydro and wind (in the base case already 100 MW of WECS have been installed).

As an illustration of the detail of output of PROMIX, Fig. 7.9 shows the power generation and the corresponding greenhouse-gas emissions of the overall system. Each figure is the graphical representation of a large matrix containing 8760 values. From left to right, there are 168 ‘‘columns’’ each representing an hour of the week starting on Monday 06.00 h and ending on Monday 05.00 h. From top to bottom, there are 52 ‘‘rows’’, each representing a week of the year. This output is also available for every type of power plant.

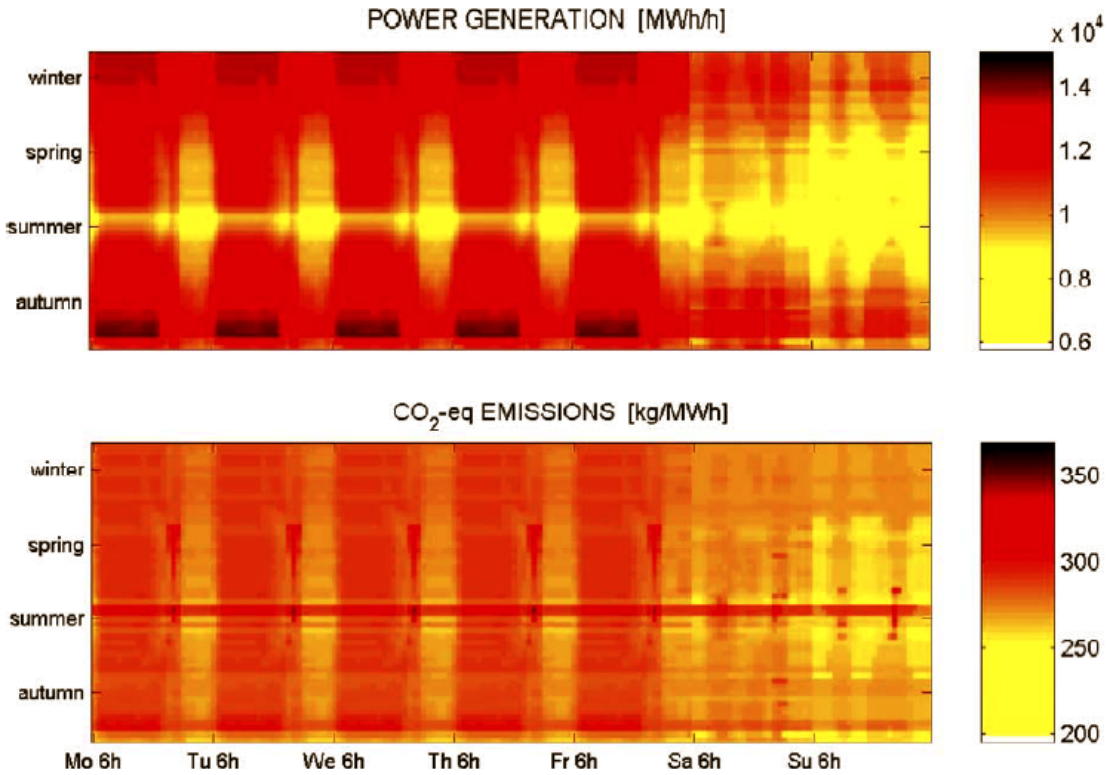

Fig. 7.9: PROMIX output; power generation and GHG emissions for every hour in the base-case scenario.

Simulations A: actual WECS output profiles, no capacity credit

In a first set of simulations, Simulations A, wind power is simulated according to the output profiles based on the actual wind measurements in Vlissingen, Middelkerke, Melsbroek and Kleine Brogel. Apart from the four cases where WECS are installed in one of the four single locations, we also consider the mixed case with an equal amount of WECS in all locations.

In all cases, three levels for WECS installation have been considered, namely 500 MW, 1000 MW and 1500MW. At a peak load of about 14.4 GW, this corresponds to installed wind power of 3.5%, 6.9% and 10.4% of peak load. At this first stage, in Simulations A, the capacity credit was disregarded which actually means that the power-generation company

does not consider the WECS in its investment plan. In these scenarios, PROMIX simulates the operation of the central power system (conventional power-generating units) whereby the wind-power output is considered as a negative load.

Fig. 7.10 shows the possible reduction in GHG emissions that can be obtained by using WECS in Belgium according to Simulations A. In all cases, the emission reduction increases with the WECS installed capacity. This increase, however, is slightly sub-linear. For Vlissingen, e.g., the emission reduction rises from 730 kton CO_2 to 1360 kton CO_2 (factor 1.8) and 2090 kton CO_2 (factor 2.8) for WECS installation from 500 MW to 1000 MW (factor 2) and 1500 MW (factor 3), respectively.

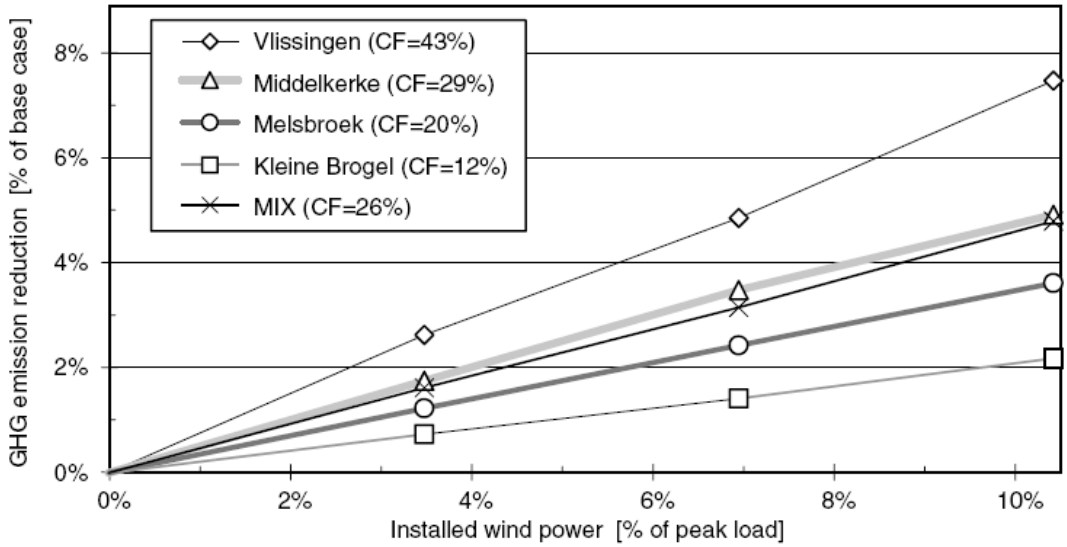

Fig. 7.10: Impact of wind power generation on the overall GHG emissions in power generation; results for ''Simulations A'' with the actual WECS power output profiles and without capacity credit.

Another obvious observation is that the GHG emission reduction increases with the capacity factor of the WECS. 1500 MW WECS in Vlissingen with a capacity factor of 43% lead to a GHG-emission reduction of 2090 kton CO_2 whereas 1500 MW WECS in Kleine Brogel with a capacity factor of only 12% result in a GHG-emission reduction of 700 kton CO_2. The mixed profile demonstrates that not only the capacity factor, but also the variability of the profile determines the possible GHG-emission reduction. With a distinctly lower capacity factor of 26%, the emission-reduction curve of the mixed profile approaches the emission-reduction curve of the Middelkerke profile with a capacity factor of 29%. 1500 MW WECS in Middelkerke are responsible for an emission reduction of 1370 kton CO_2 whereas 1500 MW WECS distributed evenly over the four locations lead to an emission reduction of 1340 kton CO_2.

In all cases considered in this section, the potential emission reduction is about 350–400 kg CO_2 per MWh of WECS power generation. This suggests that the WECS largely replace power that would otherwise have been generated by combined-cycle gas-fired units. The power-generation mix in the cases of Simulation A with 1500 MW WECS, as shown in Fig. 7.11, confirms this observation. Also note that, in the cases with 1500 MW WECS, limited modulation with the nuclear units in base load is inevitable in order to cope with the strong possible power fluctuations.

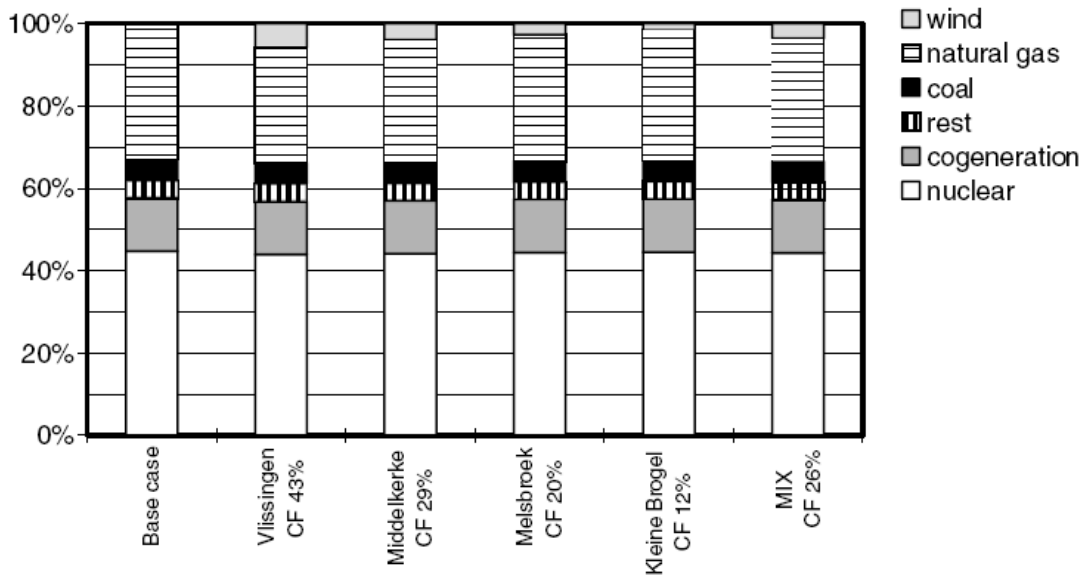

Fig. 7.11: Power generation mix in the cases of ''Simulations A'' with the actual WECS power output profiles and without capacity credit and 1500 MW WECS.

Simulations B: WECS at constant reduced output, no capacity credit

Since many simulation models lack the ability to handle detailed WECS output profiles, the power generation of wind turbines is often modeled as a constant reduced output. To verify the validity of this simplification, the scenarios of Simulations A are repeated under the assumption of a constant reduced wind-power output. In order to respect the capacity factor, the wind turbines are assumed to be constantly available at reduced power of 43%, 29%, 20% and 12% of rated power for Vlissingen, Middelkerke, Melsbroek and Kleine Brogel, respectively, and 26% for the mixed profile.

The result of the CO_2 emission reductions in comparison to the base case without additional wind power is shown in Fig. 7.12 for Vlissingen and the mix of WECS at four locations. The result for the simplified approach with WECS at constant reduced power is compared to the result using the actual fluctuating profiles. For the WECS in Vlissingen, the approach using the constant reduced power output slightly overestimates the potential GHG emission reduction by approximately 14–15% in all cases. For the other individual profiles (Middelkerke, Melsbroek and Kleine Brogel), a similar ''overshoot'' is observed. For the mixed profile, the overestimation is smaller at about 10–11%.

The reason for the overestimation when using the constant reduced power output of WECS is that the power system can be used more efficiently (especially the base-load scheduling) because it does not have to cope with the fluctuation of the WECS output. Anyway, the overshoot is limited.

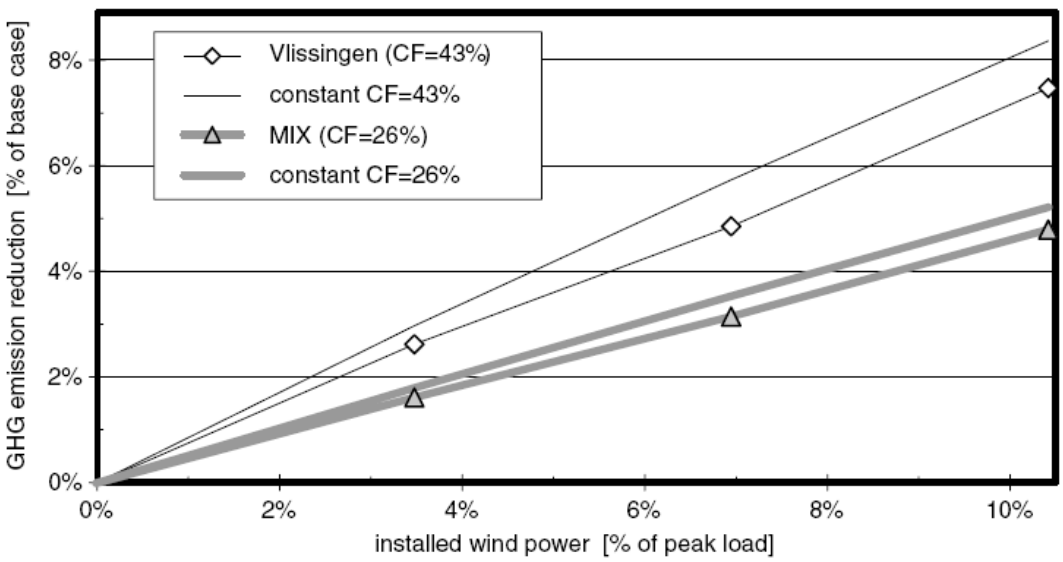

Fig. 7.12: Impact of wind-power generation on the overall GHG emissions in power generation; comparison of the results with the actual WECS power output profile and the results with WECS at constant reduced power output; results for Vlissingen and the mix of WECS at four locations.

Simulations C: actual WECS output profiles + capacity credit

In a third set of scenarios, the capacity credit of the WECS has been taken into account. This means that the WECS replace other ‘‘conventional’’ generating capacity. Because wind power is not constant and cannot be dispatched, only a fraction of the installed WECS (i.e. the capacity credit) is taken into account.

Based on the work of Van Wijk (1990), who studied WECS in the Netherlands (close to Belgium and therefore in similar wind conditions), we estimate the capacity credit for our case. In Simulations C with capacity credit, we only consider the case with a mix of WECS in the four locations because the capacity credit taken from Van Wijk (1990) is only valid for a comparable spread of wind farms. We estimate the capacity credit of the 500 MW, 1000 MW and 1500 MW wind farms at 140 MW (or 28%), 240 MW (or 24%) and 310 MW (or 21%), respectively. Since only investment in combined-cycle gas-fired units are assumed in the period up to 2010, this means that 140 MW, 240 MW and 310 MW, respectively, investment in combined cycles is avoided.

Fig. 7.13 shows the results for the scenarios in Simulations C in comparison with the results for Simulations A without capacity credit. This comparison shows that the capacity credit reduces the GHG emission-reduction potential by using WECS in a power system. The obvious reason for this unfavorable effect is that the avoided investment in gas-fired capacity - if it had been built - would have partially replaced ‘‘other’’ conventional-power generation with a higher emission responsibility. Here, WECS cause an emission reduction of about 350 kg per MWh of the power generated by the WECS. This is slightly less than the 400 kg/MWh for the case with a mix of WECS without capacity credit in Simulation A.

Fig. 7.13 also shows the GHG-emission reduction that is calculated when assuming the WECS at constant reduced power output, for the mixed case, of 26% of rated power. Here, also a small overestimation of the reduction potential of about 14% can be observed which is comparable to the overestimation noted in the cases without capacity credit.

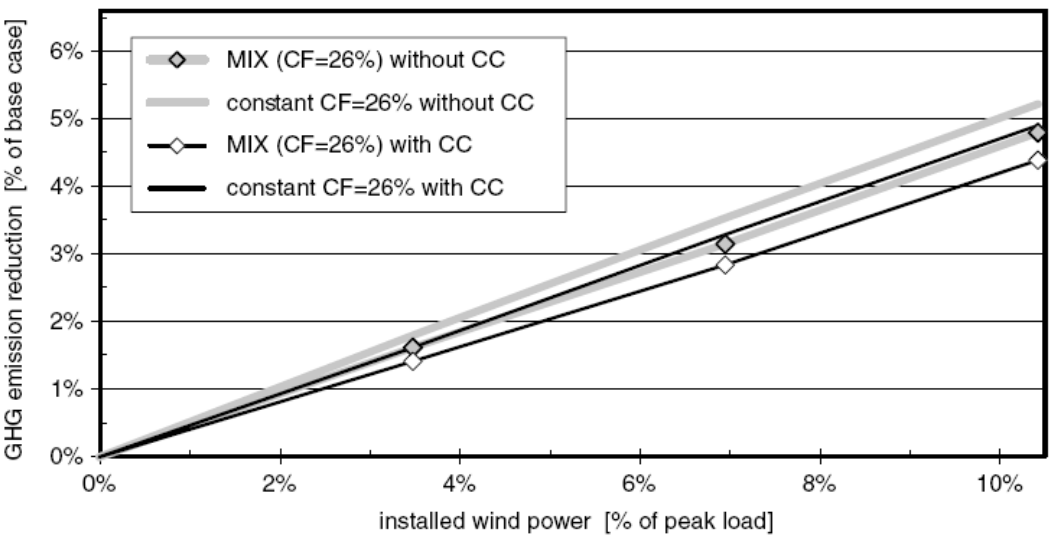

Fig. 7.13: Impact of wind power generation on the overall GHG emissions in power generation; comparison of the results without capacity credit and the results with capacity credit.

Simulations D: actual WECS output profiles + CO_2 tax

Up till now, all results have been discussed for the Belgian power-generation mix under the boundary conditions of the IEA prognoses of the energy prices. Since the GHG-emission-reduction potential of using WECS is strongly determined by this power-generation mix, it would be interesting to also investigate other generation mixes.

In order to test the influence of the generation mix, the energy prices are supplemented with a CO_2 tax of 10 €/ton CO_2 [12]. Such a tax drastically alters the proportions of the energy prices depending on the carbon content of the different fuels. The fuel prices including the tax component are now 2.39 €/GJ for coal (of which 0.96 €/GJ from the tax), 3.71 €/GJ for natural gas (of which 0.59 €/GJ from the tax) and 4.62 €/GJ for crude oil (of which 0.78 €/GJ from the tax). The emission free nuclear fuel remains at 1.09 €/GJ.

Without changes in the composition in the power system, the generation mix in the new base case including the tax alters. The coal-fired share in the power generation decreases from 5.2% (or 4.95 TWh) in the base case without taxes to 3.3% (or 3.14 TWh) in the new base case with a CO_2 tax of 10 €/ton CO_2. The gas-fired share increases from 33.0% (or 31.4 TWh) to 34.9% (or 33.3 TWh), respectively. The other generation shares remain the same.

Fig. 7.14 shows the results in which the scenario with additional WECS is compared to the scenario without additional WECS, in an environment with a CO_2 tax of 10 € per metric ton CO_2. Also the results for the same scenarios without additional taxes are shown for comparison. We only look at the results for the case with a mix of WECS in the four locations and we do not consider a capacity credit. In a CO_2-tax environment, the GHG-emission-reduction potential is larger than in the case without the CO_2 tax. The GHG emission reduction compared to the respective base cases is about 12– 15% higher for all penetration levels. This is unexpected at first sight. Although the base case with a CO_2 tax is less polluting (since a part from the power generation is shifted from coal to gas), the effect on CO_2 reduction thanks to wind power is larger than in the environment without CO_2 tax.

[12] It has to be mentioned that carbon prices are highly volatile and can change instantly with changes in regulations. In the past prices between 0 and 30 €/ton CO_2 have been seen. Thus the profit and losses of generation with fossil fuels are highly exposed to carbon emission prices.

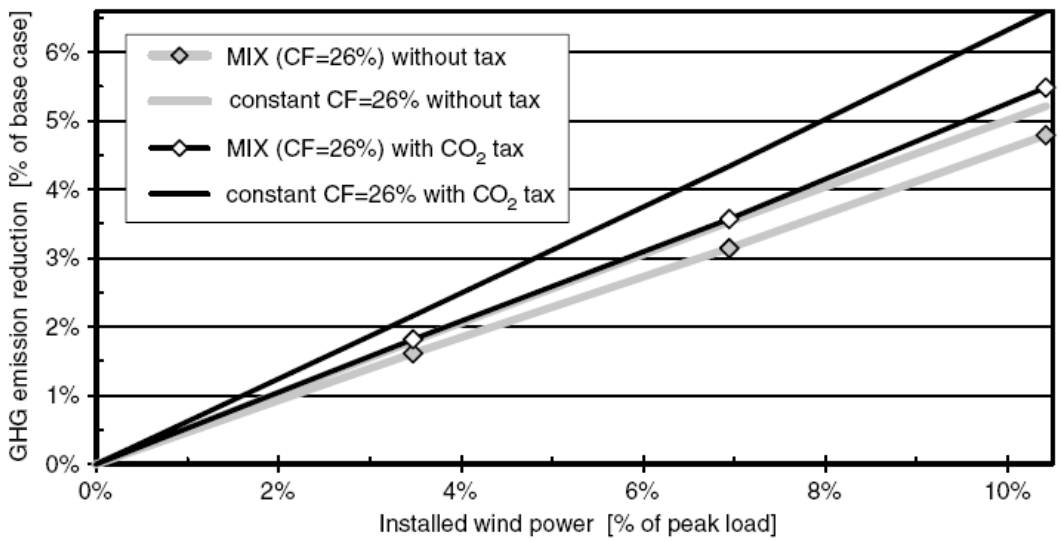

Fig. 7.14. Impact of wind-power generation on the overall GHG emissions in power generation; comparison of the results without additional taxes and the results with a 10 €/ton CO_2 tax.

When looking at the emission reduction per unit of WECS power generation, we find about 450 kg/MWh. Fig. 7.15 shows the power-generation mix for the= cases with and without CO_2 tax. The results on the left hand side already appeared in Fig. 7.11; the results on the right hand side are the results for the corresponding scenarios with CO_2 tax. It is clear that the CO_2 tax reduces the share of the coal-fired generation as already discussed earlier.

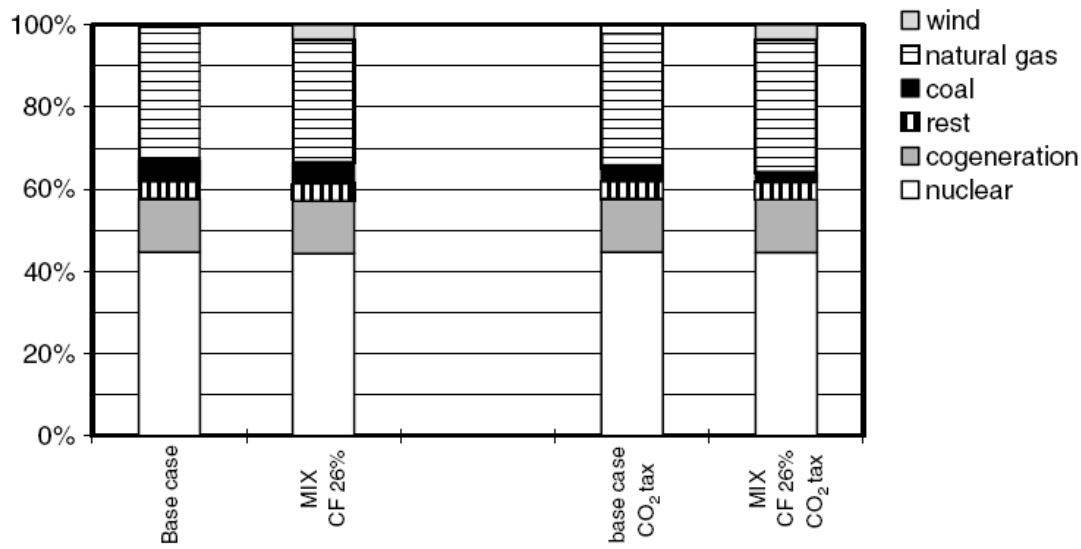

Fig. 7.15: Power generation mix for the cases with and without CO_2 tax. No capacity credit in these cases.

Fig. 7.14 also shows the GHG-emission reduction that is calculated when assuming the WECS at constant reduced power output, for the mixed case, of 26% of rated power. Here, also an overestimation of the reduction potential of about 20% can be observed, which is higher than for the same cases without CO_2 tax.

7.1.3.3 Considerations and suggestions for future research

Considerations on the spread of wind farms

The wind profiles used in the simulations discussed in the previous sections are all based on the wind measurements at one singe location. The mix case assumes equal share of WECS in four different locations, still within a radius of 100 km, varying from onshore to inland. The result of using a wider spread of wind farms (as, e.g. the entire EU territory as used by Giebel (1999) and Landberg (1997)) is that the combined power-output profile is smoother than the profiles for WECS at single locations. The local variations in power generation will nevertheless still mainly need to be compensated with local generation.

The analysis of wind data at the four locations in Belgium shows a strong correlation between the wind speeds. The reason for this strong correlation is the small distance between the locations and the lack of complex topography. Furthermore, it is noted that these correlations improve when the power output profiles are shifted in time over 1 or 2 h. Indeed, the dominant wind direction in Belgium first supplies the coastal wind turbines to later on ''feed'' those inland. This time shift between profiles results in an overall joint power generation less peaked than those based on data for a single location.

The simulations with the profile at one location as discussed in the previous parts of these Case Studies can therefore be considered as one extreme. The simulations using a constant power as discussed in Simulations B can be considered as another theoretical extreme of a very widely spread wind-farm resulting in a combined constant power output. From a simulation point of view, Fig. 7.12 shows the difference between these two extreme cases. The constant WECS output profile has a slightly larger GHG-emission-reduction potential than the strongly fluctuating profile. These differences are, however, limited to about 10–15%.

Belgium versus other regions

For all the simulations discussed above, the Belgian power-generation system was used. From a modelling point of view, this is a very interesting power system due to its variety in power plants; nuclear base-load units, coal- and gas-fired mid-load units, gas- and oil-fired peak units and pumped-storage units. The variety in energy carriers will result in a large possible swing in CO_2 emissions; from 1000 kg/MWh for older coal-fired power plants to 0 kg/MWh for nuclear power plants. Simulations for other regions with less variety in power-generating options (e.g. the Dutch system with a larger share of gas-fired power generation) will lead to smaller deviations and variability of the CO_2 emissions. Therefore, it can be assumed that the qualitative conclusions - i.e. the difference between the different cases - based on the CO_2-emission variations of a system with large potential CO_2 swing, are also valid for other systems with a lower potential CO_2 variability. The quantitative results - i.e. the total amount of GHG-emission reduction - is evidently determined by the generation mix and is system dependent.

As a next step in future research, it would be interesting to also include other regions with a different generation mix.

Influence of energy prices

All simulations up till now have been performed for the 2004 IEA prognoses for energy prices (IEA, 2004). In this work, a CO_2 tax of 10 €/ton CO_2 has been imposed which distorted the resulting energy prices. It was shown that the changes in energy prices and the resulting alteration of the power-generation mix do indeed influence the quantitative results; with a

CO_2 tax, the GHG-emission-reduction potential of WECS increased. Therefore, it would be interesting to further apply this methodology to other plausible distortions of energy prices.

7.1.4 Summary and conclusions

In this chapter a methodology to accurately determine the impact of the use of wind energy in a large power-generating system is discussed. To do so, detailed data of both the wind-power output and the power system and all of its technological boundary conditions are combined. The power generation of the central power system is simulated on an hourly basis using the model PROMIX. The impact of the use of wind power is identified by comparing two scenarios; one base case without additional WECS and one alternative case with WECS.

The method is demonstrated in an elaborate case study for Belgium in 2010. The entire power system is simulated in detail by considering every individual power plant with its own technological specifications. For the wind-power generation, hourly wind-speed measurements in four different locations are used: onshore Vlissingen, near shore Middelkerke, inland Melsbroek and deep inland Kleine Brogel. These wind-speed profiles are converted into power generation profiles by using the characteristics of a commonly used wind turbine. Different cases are studied. In all cases, we look at the GHG-emission-reduction potential of the installed WECS.

- In a first set of scenarios, the chronological power output profiles are tested for all four locations and for a geographical spread of WECS over the four sites.
- A second set of scenarios simplifies the power output of the WECS as a constant reduced power output by assuming that the WECS constantly generate a fraction, more specifically the capacity factor, of rated power.
- In a third set of scenarios, the capacity credit of the WECS is considered.
- In a fourth set of scenarios, we include a CO_2 tax for primary-energy carriers which changes the price ratios of the different fuels according to their carbon content.

As a first conclusion, in all cases considered, the GHG-emission reduction obtained on a national level is in the range of 350–450 kg CO_2 per MWh of power generated by the WECS. By way of comparison, it should be mentioned that the overall emissions of the Belgian system are about 300 kg/MWh for the complete system and almost 500 kg/MWh for the dispatchable fossil-fuel fired part of the generation mix. The emission-reduction potential increases if more WECS are installed. It can be observed that the increase in emission reduction is slightly sub-linear with the increase in installed power. If the installed power increases with a factor X, the emission reduction increases with a factor slightly below X.

Another observation is that the emission-reduction potential is larger for smoother WECS power output profiles due to a more efficient use of base-load units. Two extreme situations with on the one hand strongly fluctuating profiles of WECS in one single location and on the other hand constant power output profiles show a difference of about 10–15% in overall emission reduction. In the scenarios with a CO_2 tax, evidently the emissions are lower than in the same scenarios without CO_2 tax. Also the emission-reduction potential of WECS increases when assuming a CO_2 tax. The merit order of the coal-fired power plants is high under a CO_2 tax which makes them more eligible for incremental changes in central power delivery imposed by using WECS.

When taking into account the capacity credit of the WECS, the emission-reduction potential of using WECS decreases compared to the cases where no capacity credit is taken into account. This has everything to do with the natural emission reduction obtained by renewing the power system. It can be assumed that new and highly efficient combined-cycle gasfired units are the most eligible candidates for new investments. These units replace older units which are less efficient and produce higher emissions. The capacity credit partly inhibits this evolution which leads to a lower reduction potential. It should be noted that, in the real world, the market will decide to what extent the capacity credit will be taken into account.

7.2 Conventional generation displacement due to wind power

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7.2.1 Assessing the value of wind power

Due to its variability, wind power raises the issue of the displacement of conventional generating units. In particular, the amount of thermal units that can be replaced should be estimated.

This estimation may be done using the capacity credit concept. The capacity credit of wind power is a quantification of the effective contribution of wind generation to the power system. Since lots of definitions are given in the literature, capacity credit and load factor are often confused. However, load factor only refers to the energy whereas capacity credit deals with the power capacity.

7.2.2 Definition of capacity credit

Capacity credit may be defined as the power of conventional generating units (e.g. thermal units) that can be substituted by a variable generation (e.g. wind power or photovoltaic) without decreasing the system's reliability. It is commonly expressed as a ratio to the variable installed capacity. Thus capacity credit is highly related to the reliability of the system and is typically calculated in adequacy studies.

Wind energy opponents often claim that reserve requirements are equal to the installed wind capacity. In this case, capacity credit of wind power would be zero, which is obviously not the case. That is why the additional reserve requirements are much more limited, as reported in chapter 7.2.7. Many studies demonstrated that wind power is able to substitute both energy and conventional capacity with the same level of reliability.

Capacity credit is estimated thanks to reliability indexes like LOLE (Loss Of Load Expectation) or LOLP (Loss Of Load Probability). On the one hand, it depends on the power system characteristics (generating units, load profile and components outage probabilities). On the other hand, it also depends on wind generation characteristics like wind regimes, geographical dispersion and penetration rate.

The methodology of capacity credit assessment is reported on Fig. 7.16.

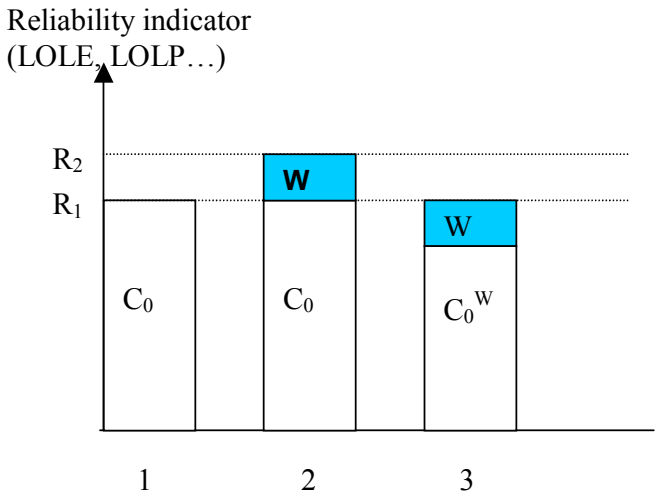

Fig. 7.16: Capacity credit assessment

Case 1: the reliability of the system is estimated considering conventional generation only (without wind). The available capacity is C_0 and the corresponding reliability level is R_1.

Case 2: wind capacity W is added to the system, and the same conventional capacity is considered. The total generation capacity is C_0+W, and the reliability is therefore at a higher level R_2.

Case 3: Conventional capacity is partly removed until the reliability level is R_1 again. The new conventional installed capacity is C_0^W.

The capacity credit CC of wind power in the system is given by the following relation:

$$CC = \frac{C_0 - C_0^W}{W}$$

7.2.3 Capacity credit of wind and penetration rate

Due to the great number of factors to be considered, extrapolation from a given power system to another should therefore be avoided. For instance, different studies demonstrated that capacity credit may vary from 5 % to 35 % of the installed capacity, depending on the considered power system. Results for the capacity credit of wind power from case studies reported in IEA collaboration [7.9] are summarised in Fig. 7.17.

Results of capacity credit calculations show a considerable spread. However, some common features may be identified, like a trend to decrease when wind penetration rate increases. One reason for different resulting levels arises from the wind regime at the wind power plant sites. For near zero penetration level, all capacity credit values are in the range of the capacity factor of the evaluated wind power plant installations. This is one explanation for low German capacity credit results shown in Fig. 7.17. The correlation of wind and load can be very beneficial, as can be seen in Fig. 7.17 in the case of US New York offshore capacity credit being 40 %. The wind capacity credit in percent of installed wind capacity is reduced at higher wind penetration, but depends also much on the geographical smoothing. This is demonstrated comparing the cases of Mid Norway with 1 and 3 wind power plants. In essence, it means that the wind capacity credit of all installed wind in Europe or the US is

likely to be higher than those of the individual countries or regions, even if the total penetration level is as in the individual countries or regions. Indeed, this is true only when assuming that the grid is not limiting the use of the wind capacity, i.e. just as available grid capacity is a precondition for allocating capacity credit to other generation.

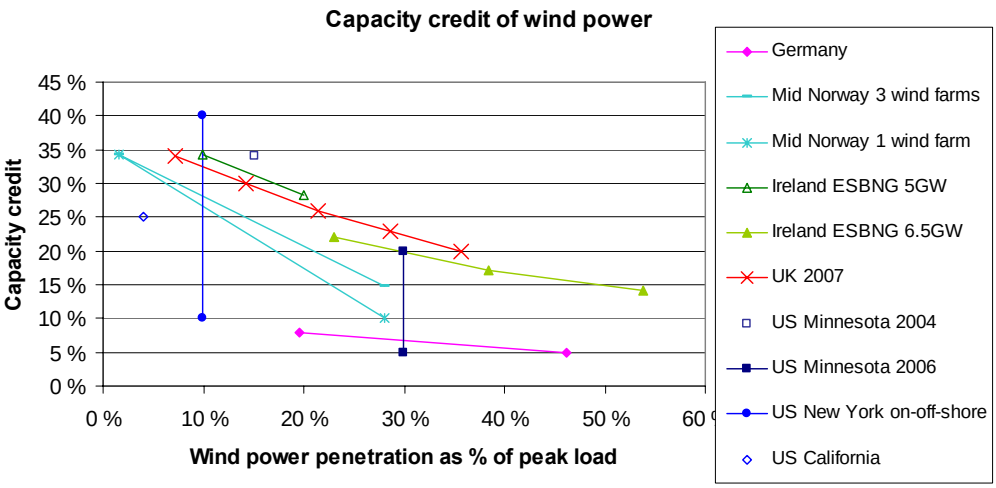

Fig. 7.17: Capacity credit of wind power as reported in IEA [7.9]

The European project Green Net EU – 27 [7.10] analyzed the capacity credit variations according to studies performed for different power systems and reported as their result the trend of decreasing capacity credit as penetration level increases (Fig. 7.18).

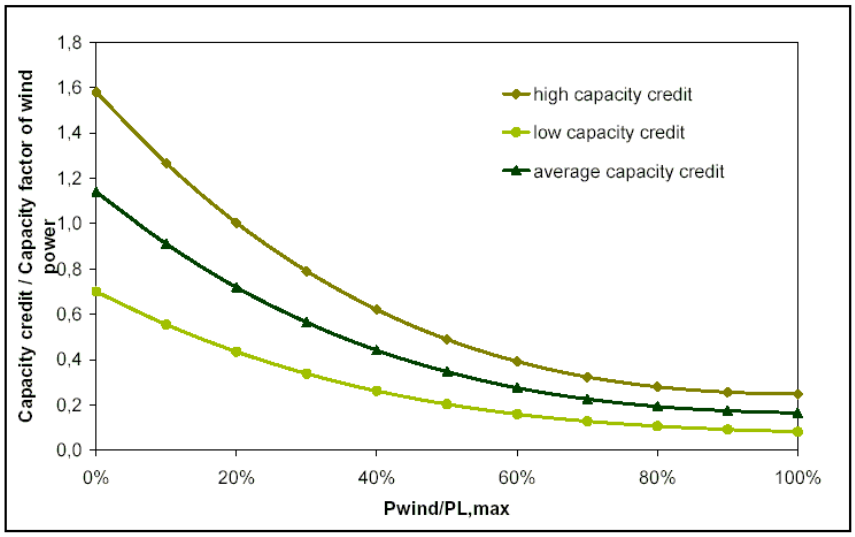

Fig. 7.18: Capacity credit / capacity factor ratio vs. penetration rate [7.10]

If the level of installed capacity is low (less than 20 % of peak load or less than 10 % in energy), capacity credit is close to the load factor. But in case of high penetration rate (in the range of 20-30 % in energy), capacity credit only represents a part of load factor. This evolution is reported Fig. 7.19, based on a simplified case close to the French power system.

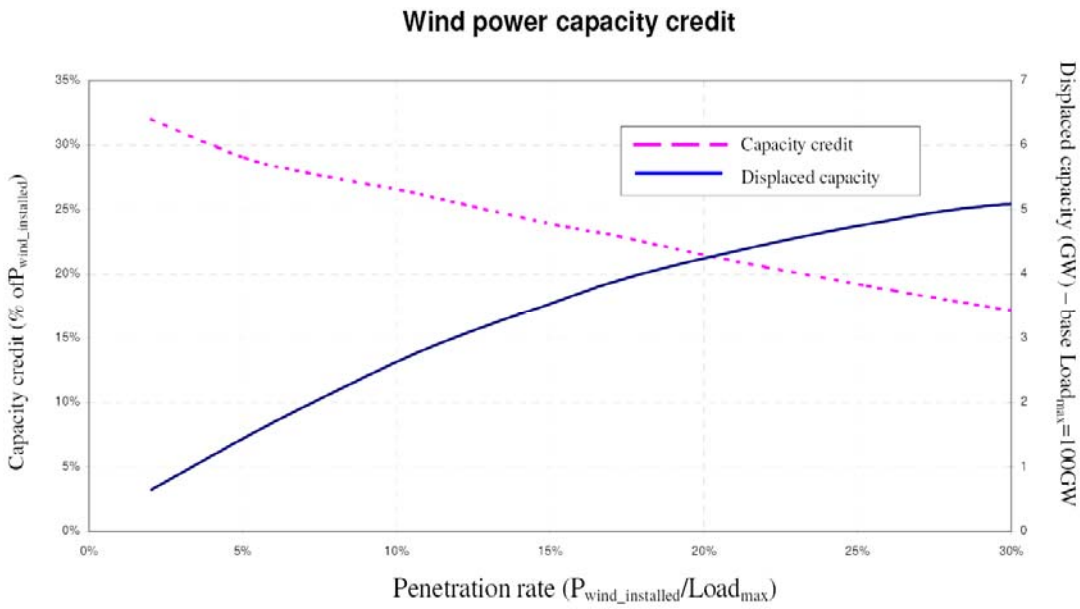

Fig. 7.19: Capacity credit vs. penetration rate

According to studies performed by the French TSO RTE (cf. [7.11] and [7.12]), wind power in France has a capacity credit of 30 % for an installed capacity in the range of 5 GW. It decreases with the penetration rate. The capacity credit would be 20 % if 15 to 20 GW were connected with the same geographical dispersion as today. In this case, wind production could replace 4 GW of conventional capacity with the same reliability.

As mentioned above, the capacity credit is strongly dependant on the climatic and geographic conditions applicable for a considered region or country. Based on measurements from Germany (s. chapter 2.3, fig. 2.11) it can be seen that for whole Germany (at least on-shore) there are about 700 hours per year where there is literally no wind. These periods can last as long as several days and often coincide with situations of high load in the grid (cold and foggy days in winter or hot summer days - remember the critical situation in Europe in summer 2003). This is the reason why in the DENA-study [7.13] a capacity credit of only 5 % has been retained.

At the beginning of the deployment of wind power stations it can be assumed that the older conventional fossil-fired power plants they were replacing, still exist for a longer time and may be used as back-up in critical situations with low wind. But in the long run this will not be possible any more.

Further investigations are also needed in order to study the simultaneity of wind availability over larger cross-national regions. At low market penetration mostly its has been possible up to now to export wind power to neighbouring regions/countries during excess situations or to import additional power when there is locally a lack of wind. It has to be proven if this will hold true also for high area-wide market penetration of wind power plants.

When studying the impact of power produced from RES it is not sufficient to consider only wind energy but also solar energy as well as biogas and biomass; e.g. it has been shown, that there is less wind available during summer month whereas this could be compensated for by solar power plants which show their maximum output during this period. In this context also the possible contribution from distributed generation in small gas-fired CHP-plants (to be installed at locations with corresponding heat demand) has to be taken into account as also their operation will be influenced by RES.

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8 The Current Status of Regulatory and Support Schemes in Various Systems and Countries

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8.1 The framework

This Chapter discusses the different support schemes for wind powered generating resources worldwide. In fact these regulatory compacts are among the basic drivers of the development of wind power.

In Europe, Directive 2001/77/EC set a 21% *indicative* share of *electricity* produced by Renewable Energy Sources (RES) in the whole Community Gross Electricity Consumption (GEC) by 2010, with national *indicative* targets for Member States. After the European Council met in Brussels in March 2007 and the subsequent Resolution of the European Parliament on the Roadmap for Renewable Energy Sources (RES) in Europe in September 2007, the EU Commission on 23rd of January 2008 published the proposal COM(2008) 19def for a new "Renewable Directive" that establishes a *binding* target of a 20% share of RES measured as a percentage of final *energy* consumptions in the sectors of electricity (RESE), heating & cooling (RESH) and transportation (REST) by 2020. The Commission also established national *binding* targets in line with the overall 20% target.

Among the various types of RES, wind is the predominant choice of many countries, with some countries having a relatively large percentage of energy in the system produced by wind. However, the integration of wind production into the grid may cause operational problems, requiring new solutions for the dispatch, balancing and control. Such issues are not only technical but entail important economical and regulatory aspects: the solution of such issues is best attained using a balanced approach involving all the stakeholders (regulators, producers, TSOs, developers, manufacturers), who sometimes have diverging "interests".

With the new and very demanding targets for RES and corresponding increase in wind generation production, it seems useful that SC 6 of CIGRE, through the Members of the

Working Group, can provide significant contributions on various technical and policy issues surrounding integration of wind generation into the grid.

In July 2007 a Questionnaire was prepared and circulated among various TSOs and experts, seeking information about technical and regulatory issues related to wind generation. After the first "round" of questionnaires sent only to European companies, additional questionnaires were also sent to Australia, Canada, New Zealand, and the US (actually response limited to ERCOT, the TSO of Texas). This additional input provides richness to the results and is in concert with the world-wide "mission" of CIGRE.

The results of the survey are presented in term of tables containing the main system data and a short "report" for each country, summarizing most of its main characteristics in this regard. In doing this, an effort has been made to make the contributions, which differ both in extent and in details, more uniform.

8.2 Institutional Environment

8.2.1 The "Renewable Directives" in Europe

The "Renewable" Directive 2001/77/CE contains an overall ***indicative*** target of 22% of ***electricity*** production in the whole EU GEC by RES for the EU-15 by 2005, which later became 21% for the EU-25 [8.1].

However, as reported in the EU Communication 24th November 2006 "Progress in renewable electricity", it is unlikely to reach the target.

The Report tracks the progress of EU Member States in 5 different categories:

i) *Perfect on track* : 3 Countries (Denmark, Germany, Hungary)

ii) *Good chances*: 5 Countries (Finland, Ireland, Luxemburg, Spain, Netherland;

iii) *Additional efforts needed*: 6 Countries (Czech Republic, Lithuania., Poland, Slovenia., Sweden., United Kingdom);

iv) *Stronger efforts needed*: 3 Countries (Belgium, Greece, Portugal);

v) *Far from commitment:* 8 Countries (Austria, Cyprus., Estonia., France, Italy, Latvia, Malta,. Slovak Republic)

Following the Decision of the European Council and of the Parliament, the Commission released its "energy-climate package" of legislative proposal, called "20%-20%,20%, on January 23, 2008. The proposal is related to: -i) a Directive for support to RES; -ii) a revised EU Emission Trading System (ETS) and –iii) a framework for deployment of Carbon Capture and storage (CCS).

The proposal of the new Directive on RES [8.2] sets an overall target of 20% of final ***energy*** consumption from renewables by 2020, ***binding*** national targets and a mechanism to allow trading ("flexibility") of RES across national borders. Concerning the key issue of how to share the EU27 20% for RES, which requires an overall increase of 11.5% from the 2005 baseline, the Commission *did not* base the sharing on the Member States' *national resources potential* but decided to choose the option to split this into two parts: a flat rate increase of 5.75% for every MS *plus* a variable increase, weighted by the Gross Domestic Product. Concerning the second portion of the effort, a citizen of the richest country in terms of GDP per head (Luxenbourg) has to contribute an amount of RES production 23 times as large as

that of a citizen of the poorest MS (Bulgaria). Trajectories of indicative interim targets of the total 20% final target have been established between 2011 and 2020. Regarding the support system for RES, the Commission also stressed the need to ensure that EU Member States (MSs) who will bear the burden of meeting the targets, also have autonomy to decide on the support system. The German and Spanish Governments expressed concerns over the likely impact of a trading scheme on their successful renewable support mechanism. Summarizing, the Proposal of the Commission, while expressing a basic preference for market-based mechanisms, states that any system of traded RES certificates, the "Guarantees of Origin (GOs)", must not upset the existing national incentive scheme. While GO trading in the EU countries can be based also on "financial basis", imports of GOs from **third** non EU-countries is allowed but: i) **only** physical power input; -ii) from new installations; -iii) when a GO system is in place. Each MS has to establish a competent body responsible for registration, issue and cancellations of GOs. The trading mechanism should be an option, not an obligation.

At the moment of writing, the European Parliament and Council of Ministers are beginning their examination of the RES and ETS Directives. The present texts concerning the sharing of the 20% target among Member States and the modalities of the GO trading are expected to raise various debates. Concerning in particular the RES Directive, discussions centre on the question whether the Directive would create a workable trading system based on the GOs: in a EURECTRIC workshop hold in Brussel on 27 March, the Chairman of EURECTRIC's Energy Policy & Generation Committee, backed by most experts present, did not see the present form creating a functioning RES trading system as it would allow only very limited trading between MS governments, rather then companies.

8.2.2 The situation in the U.S.

The US wind power market continued its rapid expansion in 2007, with 5,244 MW of new capacity added and a cumulative total of 16,818 MW [8.3].

The amount of offshore wind capacity being proposed at the end of 2006 was 2,455 MW in eight states, the largest being Massachusetts (on the Atlantic Coast) and Texas.

A variety of innovative ownership and financing structures have been developed to serve the purpose of allowing equity capital to fully access the federal production tax incentives available for wind resources. These structures typically *involve no debt at the project level*. The year 2007 saw a continued expansion of the number of equity and debt providers to wind projects and this continued to drive down the cost both of equity and debt for wind projects.

Electric utilities have begun to express greater interest in owning wind assets. Of the cumulative 11,575 MW of installed wind capacity at the end of 2006, Independent Power Producers (IPPs) owned 85%, utilities 13% and small community-based owners held just 2% [8.4].

Investor-owned utilities (IOUs) continue to be the dominant purchaser of wind power in the U.S. with 58% of the cumulative capacity selling to IOUs. Power marketers were purchasing power from 1% of the total power capacity. Owners of wind projects are taking on some merchant risk and some portion of their revenues is tied to short-term spot market energy sales. The majority of this activity exists in Texas and New York where wind power is able to compete with conventional natural gas-fueled generation due to high spot market prices driven by natural gas price.

The price of wind power shows variability, caused in part by regional factors, but also because of development and installation costs depending on a region's physical geography,

population density and regulatory processes. Texas and the so called "Heartland" (central interior region of the U.S.) show the least cost of wind generation on average, while California, the Great Lakes and East regions are areas with highest costs.

A recent report of the Lawrence Berkeley National Laboratory [8.5] present a very complete survey on the status of the Renewable Portfolio Standard (RPS) mechanism adopted in the U.S. to support the renewable sources. The RPS have proliferated at the *state* level in the U.S. since the late 1990s. At the end of 2007, mandatory RPS policies have been created in 25 states and Washington D.C.; four additional states have non-binding goals. Of the 26 programs in existence at the end of 2007, half had been created since the beginning of 2004.

The design of an RPS varies, but basically requires electricity suppliers (LSE) to procure a minimum quantity of eligible renewable energy. Design variations among states are rather stark: the tailoring of RPS design to satisfy particular state objectives is a typical aspect of state policy making. Some states have established "tiered" targets or set-asides for different resources types. Many states have exempted certain Load Serving Entities (LSEs) or end-use customers from meeting RPS requirements: in particular states often exempt some or all of the Publicly Owned Utilities (POUs) from formal RPS obligations. States also adopt different eligibility rules related to geographic location and electricity delivery. If renewable electricity must be delivered to LSEs under RPS obligation, a practical limitation is placed on the distance of renewable project from the state in question. Unbundled RECs, on the other hand could potentially satisfy an RPS without any geographic constraints. Because state interests encouraging in-state or in-region development vary, and because wholesale electricity market structures differ, a variety of approaches have been used to limit the geographic eligibility of renewable energy projects and to establish electricity delivery requirements.

Even if the focus of most RPS activity has been within the states, the U.S. House of Representatives and Senate have, at different times, each passed versions of a Federal RPS, which however has not yet been signed into law. The U.S. House of Representatives passed Federal RPS in 2007, but the bill was unable to pass out of the U.S. Senate. The House-approved RPS would have required certain retail electric suppliers to include 15% renewable resources in their electricity mix by 2020.

In 2007, four states (Illinois, New Hampshire, North Carolina, and Oregon) established new RPS policies, 11 states significantly revised pre-existing RPS programs to strengthen them, and three states created non-binding renewable energy goals. By 2012, forty-six percent of nationwide retail electricity sales will be covered by the mandatory state RPS policies established through the end of 2007. RPS are increasingly motivating renewable energy development. Over 50% of the *non hydro* renewable capacity additions in the U.S. from 1998 through 2007 occurred in states with RPS programs (~ 8,900 MW). State RPS policies are primarily supporting wind power, though some resource diversity is apparent. Of the mentioned 8,900 MW, 93% of these additions came from wind power, with biomass (4%), solar (2%), and geothermal (1%) playing a lesser role.

Assuming that full compliance is achieved, current mandatory state RPS policies will require the addition of roughly 60 GW of new renewable capacity by 2025, equivalent to an additional 4.7% of projected electricity generation in the U.S. Even with this growth, however, non-hydro renewables would provide a modest contribution to U.S. electricity supply, evaluated to 6% of total projected generation in the U.S. by 2025.

Mandatory RPS policies are backed by various types of compliance enforcement mechanisms and many, but not all, include the trading of Renewable Energy Certificates (RECs). REC markets are highly fragmented in the U.S. and consist of two types: -i) compliance markets in which RECs are sold to meet a Renewable Portfolio Standard (RPS) and - ii) "green power" markets in which RECs are sold on a voluntary basis to verify renewable content. Key trends in compliance markets in 2007 include continued high prices to serve the Massachusetts RPS, increasing prices under Connecticut RPS and declining prices in Texas. RECs offered in voluntary markets continued to have prices under $5/MWh in 2006 [8.4].

An increasing number of states have begun to design their RPS policies to provide differential support to promising but currently higher-cost renewable technologies or applications. Typically, this support has been provided either through *"credit multipliers"* in which favored renewable technologies are given more credit toward meeting RPS requirements than other technologies or through *"set-aside"* in which some fraction of the RPS must be met with favored technologies.

Renewable energy certificate tracking systems continue to expand. In 2007 two new regional electronic certificate tracking system were completed, the Western Renewable Energy Information System (WREGIS), serving the Western Electricity Coordinating Council (WECC) and the Midwest Renewable Energy Tracking System (M-RETS). These two are added to the existing ERCOT (Texas) system developed in 2001, the GIS (New England Power Pool) developed in 2002 and GATS (PJM pool) developed in 2005. With the increased availability of formal certificate tracking system, most RPS states have opted to allow, with restrictions, the use of unbundled RECs for compliance. As of the end of 2007, all but four RPS states allowed unbundled RECs to count towards compliance.

The Authors of the Report [8.5] report that, despite various limitations related to the complexities of the evaluations and recognizing that the cost impacts of the state RPS policies have varied by state, there is little evidence of a sizeable impact on the average electricity rates, so far. In most cases, rate increase associated with existing state RPS policies, for those states in which such impacts are readily calculable, are generally estimated at 1% or less.

States are increasingly recognizing transmission as a key limitation to achieving RPS targets: states and grid operators are taking steps to encourage transmission investments often within the context of growing state RPS obligations. Examples are: -i) Texas. Competitive Renewable Energy Zones (CREZs) were created, the PUC is authorized to order a utility to expand or to construct transmission to meet Texas RPS; -ii) Colorado, where in January 2007 a legislation was enacted modelled, to some degree, after the Texas CREZ approach. The legislation requires utilities to submit biennial reports designating energy resources zones (ERZs) and identifying transmission plans for accessing the ERZs; -iii) California. The ISO received FERC approval for a new transmission interconnection category for location-constrained resources such as renewable energy facilities in late 2007. Transmission will be built in advance of generation being developed and costs would be initially recovered through the California ISO transmission charge; -iv) Minnesota's RPS requires utilities to file five-year.

8.3 Overview of the RES support mechanisms in Europe

In Europe, the major mechanisms used as the driving force of RES development are:

i) Feed-in Tariffs (FiTs) and

ii) Tradable Green Certificates (TGCs), or "Quota systems".

Other less used mechanisms are: -iii) tenders; -iv) tax incentives; v) a mix of the previous mechanisms.

With the ***FiT*** mechanism a ***regulatory body sets a technology-related price*** *for a period of several years*, to be paid to producers of RES. The purchase price of energy production by the TSO or Distributors is ensured. ***The result is the quantity of renewable energy*** that can be provided by each technology. The costs are passed to the consumers. The *"advantages"* are: -i) the return on the investments is guaranteed; -ii) the possibility of promoting mid and long term technologies; -iii) the support (incentives included) is paid only to the energy produced. The *"disadvantages"* are: -i) it is not a "market based" mechanism; -ii) there is the risk of

over funding, if the learning curve for each RES technology is not built in as a decrease of the tariffs over time to follow the decrease in production costs.

So far it is the most widely used method in the EU25: 18 countries + Italy for solar PV.

The FiT mechanism has been implemented in the various European nations with some differences, concerning the updating (timing and amount of reduction) of the yearly tariffs, whether or not linked to the Retail Price Index, the possibility to choose to sell the energy directly to Distributors at an overall price or to the TSOs at market price with a "premium", with or without price caps.

Under the ***TGCs*** mechanism, the ***quantity of RES production is fixed by the regulatory body***, ***the output*** of the mechanism is ***the price***. The rationale is to split the "green" characteristic of renewable production and to trade it separately from the *commodity energy*, sold at market price. In order to finance the additional cost and ensure the Renewable Obligation (RO) is met, all the consumers/distributors (UK) or Producers/Importers (Italy) are obliged to purchase the Green Certificates in the amount ruled by the regulatory body. Penalty payments for non-compliance are likely.

In principle, the *"advantage"* is that the mechanism should be market based, since producers/consumers should buy the necessary certificates in a market where RES producers compete with each other. *The "disadvantages"* of the mechanism are: -i) typically only lower cost renewable technologies are developed; -ii) not well suited to support emerging high cost technologies; -iii) can create uncertainties for investors, especially when quota obligations are not fixed for an extended period; -iv) results in higher administrative costs.

Currently the TGC mechanism (with some variations) is utilized in UK, Italy, Sweden, Belgium and Poland. UK and Italy have recently made changes on the original TGC mechanism to overcome the criticism made on its application..

8.4 Country Profiles

Australia

Main characteristics of the system and of the RES. The National Energy Market & Management Company (NEMCO) is the sole market and system operator, responsible for the dispatch of generation and for system security. There are six regions spanned by the National Energy Market (NEM), with a dominant transmission network service provider (TNSP) in each region. There is one regulatory body, the Australian Energy Regulator (AER) for the six NEM TNSPs. There are also a number of distribution network service providers (DNSP). Network service providers are the network owners.

Incentives and tariffs. Federal Government and Australia's States (Queensland, New South Wales, Victorian, South Australian) have developed laws to provide incentives for investments in renewables. While the Federal Government's Mandated Renewable Energy Target (MRET) is specifically designed for renewable generation only, the state based scheme also cover low emission gas generation and other emission reduction techniques. A quota system best describes the support mechanism. Electricity retailers and other wholesale buyers of electricity (liable parties) are required to acquire renewable energy certificates (RECs) from accredited renewable energy generators or displacement sources. Any accredited renewable electricity generation or displacement project are eligible to earn RECs. RECs are traded in markets that are separated from the physical power markets. The number of RECs that liable parties are required to acquire is based on their share of national electricity purchases.

The overall costs of the support mechanisms are not paid for by the consumers by an explicit supplement to a customer bill, but rather are "captured" by increases to consumer charges due to increased wholesale cost of electricity. Consumers who have elected to purchase "green energy" from their retailer are charged a premium for doing so, which may appear on their bills.

The wind capacity is expected to increase from the 689 MW of October 2007 up to 7,670 MW by 30 June 2012.

Connection to the network. In the NEM, generation developers normally fund connection assets, and these are added to the transmission. Deeper augmentation within the grid necessary to allow unconstrained operation must be justified using the "regulatory test", which has a *reliability limb* (used for considering reliability driven augmentations, based on the service obligations imposed on TNSPs) and a *market benefit limb* (used for assessing non-reliability driven investments, concerned with assessing the present value of a project's benefits against the present value of its costs). A proposed transmission augmentation is required to satisfy at least one (but not necessarily both) of the limbs to become a regulatory asset. It is likely that transmission augmentation to address congestions impacting wind plants would need to be justified under the *market benefit limb*, which is more contentious and difficult to apply.

Dispatching. All intermittent generation is classified as "*non scheduled"* and has priority of dispatch. Changes are currently before the Australian Energy Market Commission to allow "semi-dispatch" arrangements, under which wind farms could be required to reduce output. In South Australia it is required that new wind farms are registered as *"scheduled generation",* subject to the same rules as other generators. *Non- scheduled* wind farms do not need to provide energy market bids but if sufficiently large need to provide NEMMCO with SCADA identifying their output. Significant wind farms will be required to provide in real time the number of units operating, wind speed and wind direction. A centralized forecasting tool is being developed relying on these SCADA measurements.

Balancing. Generating units enabled for Regulation Frequency Control Ancillary Services (FCAS) are determined on the basis of FCAS bids: currently the cost of additional Regulation FCAS would be paid by customers. If *scheduled wind farms* and *semi-scheduled wind farms* contribute to imbalance they can be required to contribute to Regulation FCAS costs, through a *"causer pays"* arrangement.

Real time Control. Scheduled wind farms can be constrained by the NEM central dispatch engine; *non-scheduled* wind farms may be fitted with local generation dispatch limiters. Constrained-off compensation is not normally paid. Theoretically also a compensation arrangement should be negotiated with the local NSP, but in practice this does not apply. To support the introduction of semi-dispatch, new wind farms are required to be capable of active power control.

Frequency control. The National Electricity Rules (NER) are as far as practical technology neutral. To enable a generator (independent of fuel source type) to participate in the electricity market it needs to be registered: part of the registration requirement is for the generator to meet the technical access standards. Most wind plants, to avoid spilling wind, choose the minimum access standard to the NEM which requires that the wind plants active power does not : i) increase in response to a rise in system frequency; -ii) decrease more than 2%/Hz in response to a fall in system frequency; -iii) they must remain connected to the power system to frequency down to 47 Hz. The FCAS market allows frequency control providers to be compensated. It is however unlikely that standard wind plants design can provide sufficient frequency control to participate in FCAS.

Voltage control. Wind plants are required: -i) to regulate voltage at the connection point within 0.5% of its set point; -ii) the reactive power rise time following a 5% step change in the voltage set point is less than 2 seconds. If wind plants are able to provide voltage support

in excess of their performance standard they could provide reactive power ancillary service. To date no wind farms are located and designed such that they can provide reactive power services.

Fault ride through capability (FRTC). All generating units, including wind plants, are required to have FRTC. However, the obligation is placed on the whole system and not on individual generating systems.- This is an ancillary service which is a market service and may be provided by any generating system across the NEM. Wind plants can negotiate "to trip" if, following a fault in the T or D system: -i) the total reduction in generation is less than 100 MW; -ii) the wind farm is unlikely to have an adverse impact on the quality of supply. There is no obligation on generators to retrofit new controls to meet new access standards. Retrofitting may be necessary if a wind plant was found to be unable to meet its performance standard.

Canada

Main Characteristics of the system and of the RES. Canada's large land mass and lengthy coastlines give it perhaps the world's best potential wind resource. More than 50% of Canada's energy needs are currently supplied by large hydro. Canada is characterized by long distance north-south transmission lines. As a result, transmission and distribution losses are relatively high (8%). Currently there are no off-shore wind installations in Canada.

Mechanisms to support wind. Currently, the federal government has remodelled the previous Wind Power Production Incentive (WPPI) as the ecoENERGY program. Up to 4,000 MW of renewable projects commissioned between April 2007 and March 2011 are eligible to receive a one cent per kilo-watt hour (kWh) payment for the first 10 years of operation. Canadian income tax regulations allow taxpayers an accelerated write-off of 50% of the eligible capital costs. In addition to federal incentives, each province in Canada is experimenting with its own wind policies. Most provinces are issuing requests for proposals (RFPs) for specific volumes of capacity and then signing power purchase agreements. Alberta has a wholesale energy market. The independent system operator plays no role in centralized generation planning. However, the Alberta government has set a target of 3.5% of total electricity supply be from renewable resources by 2008. All generators may request to connect and compete on the wholesale market.

In general, the support mechanisms have been sufficient to stimulate significant growth in the wind industry in Canada. With the current Federal and Provincial incentives and targets, starting from a installed capacity (2006) of 1,534 MW, targets of 6,000 MW for 2010 and 16,000 MW for 2025, when wind is expected to supply 5% of the domestic demand, are anticipated.

Characteristics of feed-in tariffs. British Columbia and Onatrio offer feed-in tariffs between 65 and 79 C$/MWh for wind projects < 10 MW connected to the distribution system. Prices can be location dependent and are escalated annually based on the consumer price index (CPI). Minimum purchase-prices (C$ 77.5/MWh) have been legislated in Prince Edward Island. The price is also adjusted based on the time of day and month of delivery.

*Green Power Program and Certific*ates. There are green pricing programs for direct sales of green energy and also green certificate programs offered by various companies for supporting the development of new green initiatives. Prince Edward Island is exporting both wind energy and renewable energy credits to the U.S., where RECs are better defined in states that have renewable portfolio standards (RPS). The value of RECs varies depending on the market between $5 and $90/MWh with a value of $20 being typical.

*Network Planning for Wind Capa*city. The Planning Authority in each province determines the shallow and deep connection charges: the Generator is expected to pay both. There may be cost recovery depending on the details of a particular request for proposal. The deep connection charges are associated with interconnection system upgrades or network upgrades

depending on the type of transmission service taken by the generator. If non-firm transmission service is taken, the deep connection charges will be lower but the generator is subject to curtailment if there is grid congestion. Currently generators in Ontario are not subject to transmission tariffs but only for the cost for the shallow charges. The Ontario Power Authority is proposing that the cost of enabler lines built to connect clusters of renewable resources be socialized and regulatory obligations streamlined to ensure that renewable targets can be met.

Dispatching and scheduling. In most jurisdictions, if there is no congestion, the wind generator is permitted to self schedule. There is no difference in priority between wind and other renewable forms of generations. In Ontario, intermittent generation is self scheduling and is not permitted to bid into the market. Wind resources are treated as price takers in the hourly spot market. Dispatch algorithms ensure intermittent renewable generators operate with curtailment as a last resort. Wind generators are also treated as price takers in the Alberta energy market. There are times in Alberta when there is insufficient ramp rate available in the energy and ancillary services markets to keep up with fast wind ramp events. Improvements in wind forecasting and wind power management tools are being pursued.

Wind forecasts. Wind forecasting requirements vary depending on the provincial grid codes, power purchase agreement requirements or energy market rules. Hourly wind forecasts are provided to the Ontario IESO once per day by the wind plant operator covering the next 48 hour period. It is expected that more than 1000 MW of Distributed Generation will connect over the coming years. Ontario is investigating wind forecasting and impact of wind forecast error on market costs. Forecasting and telemetry requirements for these generators are under discussion. Manitoba Hydro requires meteorological data to be supplied and they perform their own forecasting.

Balancing. There are currently no penalties for wind energy imbalances in the Ontario or Alberta markets. Those jurisdictions that have transmission tariffs based on U.S. FERC Order 888 provide energy imbalance as an ancillary service. In other jurisdiction, some tariffs provide preferential treatment for "non-dispatchable" generation such as wind in the form of larger bandwidth of scheduled versus delivered energy over a one-hour period.

Real Time Operation. The majority of plants have been placed in-service in the past three years so they are equipped with modern control capability. Several grid codes in Canada require the ability to set production limits if there is grid congestion. Typically, the TSO will not provide any rebate if a generator must be curtailed.

Remote Control of Wind Plants. Wind farm cluster management (WFCM) is not needed at present because large wind plants typically already have some form of production control. This scheme will likely be investigated in Ontario because of their Standard Offer Program stimulating a lot of interest in distribution connections (e.g. 1000 MW).

Frequency Control. At present, wind production has no obligation for primary or secondary frequency control in Canada. In Quebec, future wind plants will have to be equipped with a frequency control system capable of making an inertial contribution comparable to that of conventional generating stations during substantial drops in frequency. Conventional generators are not paid to provide this service so it is unlikely wind generators will either. At minimum, wind generators must be able to ride through expected frequency excursions between 58 and 62 Hz.

Voltage Control. Large wind plants (typically greater than 10 MW) connected to the transmission system have to provide voltage control and typically a ±0.95 pF reactive power range. If the wind plant is capable of providing additional capability and the TSO finds the capability useful (to avoid congestion or to facilitate other transactions) the capital cost of the reactive power is eligible for some rebate.

Fault Ride through Capability (FRTC). Fault ride through is currently mandatory. There is no special fee paid to producers providing such a turbine. Existing machines are grandfathered against this requirement. Luckily there are very few of these turbines installed across Canada.

Denmark

Main characteristics of the system and of the RES. On October 1st 2005 Eltra in West Dk (interconnected with UCTE) and Elkrfat in East Dk (connected to Nordel) merged together with gas transmission (Gastra): all together they became Energinet.Dk, which participates in Nordpool. Since Western Dk is not interconnected with Eastern Dk both regions form *different pricing* zones. However, both regions are indirectly connected through interconnections with Germany and Sweden. This aids wind integration as it gives the TSO the resources to compensate the imbalances. Nordpool has a day ahead hourly market Elspot and a market, Elbas, where continuous trading is done up to the hour (h-1) before the delivery time.

The majority of wind development took place in Western Denmark, accounting for about 75% of the capacity installed: the need for integrating the wind production (and CHP) modified over the years the structure of the system which gradually became a "distributed network". The two existing offshore wind farms (Horns Reef) are in the South Western Dk.

Tariff evolution. Denmark was the "motherland" of wind production in Europe until 2001, when the Government decided to shift from "feed-in tariffs" to a mechanism linked to the market price. Until then, the wind production received since the beginning of eighties, 60 Ore/kWh (about 80 €/MWh at a exchange rate of 1 €=7.5 DDK). This stable price triggered on one side the development of the wind turbine industry and on the other side the high penetration of wind production. The change in the support mechanism introduced instability and the result was that only a few new wind turbines were installed in 2004 and 2005. Denmark's current wind policy focuses on a five year (2005-2009) program of 350 MW eligible for repowering incentives, called "scrapped turbines certificates" which guarantee a higher purchase price for a limited period of operation. The Danish settlements rules for wind production are very complicated and various categories exist, depending on age of commissioning, accumulated production and the siting on shore or off shore. The basic distinction is:

- on shore production: various feed in tariffs, linked to the market price
- off shore production: tender procedure. Production sold on commercial market and a subsidy determined in the tender procedure.

The total RES production in 2006 was 9.6 TWh , which is 26.6% of the gross electricity consumption. Wind (6.1 TWh) contributes to 16 % of total gross demand. It is probable that Denmark will reach the 29% "burden sharing" of the "Renewable" EU Directive 2001/77/CE by 2010.

*Balancing***.** Energinet informs the demand side three months in advance of the hourly percentage of wind that consumers can purchase. The differences between the three month and the 12 hrs forecast are balanced in the Nordpool market. Energinet, responsible for the major part of the wind production (70%*6.1 = 4.3 TWh), sells it into the Nordic Elspot market every day. That gives the TSO an overview of the planned wind production for the coming day.

The "new" onshore WTs, commissioned after 2003, are treated as conventional thermal plants, that is they have to pay the unbalance costs. The "old" WTs, before the end of their production quota, are exempt from the balancing costs. Energinet pays the costs and includes them in the tariff paid by the final consumers, together with the subsidies for "green electricity". Imbalances between schedules and deliveries are balanced in the Nordpool regulating market. Denmark uses a *"two-price"* imbalance system: a market participant pays

imbalances if his hourly imbalance has "the same sign" of the overall system imbalance; on the other hand he is paid the spot price of the regulating market when the imbalance he introduces is opposite to the system imbalance and therefore contributes to its reduction.

Dispatching. Wind production has a priority dispatch against CHP and Energinet bids wind production at a "notional price" of zero. It is difficult/not possible to stop the wind production. If market agents (TSO as agent for wind production) sell too much in the El-spot, Energinet sells the wind production into the Nordel regulating market or exports the excess to Germany. Otherwise CHP plants are regulated down to a minimum and Energinet also tries to stop the decentralized power plants. There is an emergency plan available that makes it possible for the TSO to stop the decentralized power plants.

Wind Farm Cluster Management (WFCM). At the moment it is not possible to control the onshore wind power via WFCM, but this is planned for wind turbines connected to the network > 100 kV. The TSO will specify requirements for the WFCM in the connection code. Presently it is possible to control the 150 MW of off-shore wind power via WFCM. It is the owner that has the responsibility to secure the regulation.

Fault Ride through Capability (FRTC). The FRTC is mandatory for all the WF connected after 1.12.2004 to the network > 100 kV. No retrofitting of the old ones is required, but almost all were already equipped with the FRTC.

France

Main characteristics of the system and of RES. The French burden sharing of RES under the EU Directive is 21% by 2010. It is largely dependent on the contribution of the hydro production, which represent 70% of the total target. The TSO adequacy report published in 2007 and used by public authorities to establish the investment plan, considers an expected wind capacity of 5,000 MW.

Support mechanism and tariffs. Wind energy support mainly relies on Feed in Tariffs for projects below 12 MW (mechanism introduced in 2001). Most of the connected wind plants are below 12 MW due to the purchase obligation limit. Some competitive tenders for special projects exist: an offshore wind farm project of 105 MW in Normandy is currently being studied.

In July 2005 the "Zone de Developpment Eolien" (ZDE) were introduced, with a minimum and maximum installed capacity defined. A transitional period took place between July 2005 and July 2007. Before July 2007 the purchase obligation applied to all wind plants < 12 MW. Now it is mandatory for new installation to be sited in the ZDE.

Dispatching. RES enjoying the purchase obligation (wind farms < 12 MW or within a ZDE) have priority of dispatch and the production is accepted "as it comes". When risks of grid congestions are identified during distributed generation connection studies performed by TSO/DSOs, curtailment periods (maximum yearly duration and periods of the year) may be defined.

Balancing. Wind producers have no obligation to present a dispatching schedule. There are no balancing costs on wind producers. Wind energy is the balancing responsibility of the whole Electricitè de France(EdF) production and EdF clients: there is no distinction between the different balancing costs.

Remote control. Presently no remote control of wind farms exists

Fault Ride through Capability. FRTC is compulsory only for the injections into the transmission network. However, almost all wind production is injected into the distribution network, which presently has not such obligation. New requirements are to be expected concerning FRTC also for the distribution Network.

Germany

Main characteristics of the system and of RES. Wind energy is the leading source of renewable energy in Germany. In 2006 the installed capacity was 20.6 GW with a production of 30.5 TWh, corresponding to a share of 5% of national final electric consumptions.

The total Renewable Energy (RES) produced is 12%; it is therefore probable that the target of 12.5% of the EU "Renewable" Directive can be easily obtained.

According to the well known German Energy Agency Dena study (2005), wind installations can expand to 36 GW (26 GW onshore and 10 GW off-shore) in 2015 and to 48 GW in 2020. By 2015, the yearly production should increase up to 77.2 TWh, providing 14% of the German net electricity consumption.

In Germany there are four TSOs: Eon Netz, Vattenfall Europe Transmission, RWE Transportnetz Strom and EnBW Transportnetz.

Tariffs. Germany is a strong supporter of the "feed-in tariffs". The FiTs for wind are based on a two-step structure: "initial" and "basic". No inflation correction is ruled. For *on-shore* plants: -i) the "initial tariff" is paid for ca. 5 years (concrete time depends on generated energy) and the basic tariff for 15 years; -ii) an annual reduction of 2%/yr is in force, starting from 2004. –iii) The two values paid in 2007 were 81.9 €/MWh for the initial tariff and 51.7 €/MWh for the basic tariff.

For *off shore* plants, starting from 2004 the mechanism is based as follows: -i) The *"initial"* and *"basic"* tariffs were respectively 91.0 €/MWh and 61.9 €/MWh; -ii) the annual reduction of 2%/yr starts from January 2008; -iii) plants that go into operation before 2010 get the higher "initial" tariff for 12 years. New higher tariffs for off-shore plants are in preparation.

Dispatch. The wind production has a priority dispatch against conventional thermal production but not against other RES. Until now, there is *no obligation* for the wind plant operators to submit a scheduling program or forecast for the next day: therefore the TSOs have to do the forecast for the wind electricity by themselves. The TSOs purchase from the market the balancing needs and pass the full cost to the consumers in the transmission tariff. All wind production is fed into the system, but each TSOs takes only a pre-fixed part, established by an inter-TSOs equalization scheme. The difference between production and what is taken is physically and financially exchanged with the other TSOs, according to a sharing criterion.

TSOs can limit the wind energy production only in *very critical* power flow situations; some wind turbines are equipped with a Remote Control through the Cluster Management. It is not yet compulsory but it can become so for the future. No money is received by the producers for the energy lost.

Fault Ride through Capability (FRTC). A law is in preparation to make FRTC compulsory for the old and new wind turbines. For old wind turbines a rebate is anticipated.

Frequency regulation. No obligation exists for either primary or secondary frequency control.

Ireland

Main characteristics of the system and RES. The RES (wind and others) account for roughly 10% of the Ireland's energy at present. The target for 2020 is 33% energy from RES.
Tariffs. Ireland *utilizes "feed-in tariffs",* and in general the various stakeholders are happy both on the existing mechanism and on the tariff level. They are indexed to the Retail Price Index (RPI).

For wind the tariffs for off-shore plant over 5 MW are *not* different: 57 €/MWh. The tariffs are slightly higher for small scale (< 5MW) wind plants: 59 €/MWh.

Dispatching. Wind production has a priority of dispatch and presently there is no conflict between hydro and wind, but in the future wind might be put as a second priority to hydro. In case of a dangerous situation for the network, the TSO may curtail wind production. A rebate for the wind production eventually curtailed is foreseen but there is no policy on this yet.

Scheduling. Small scale producers (< 10 MW) do not normally schedule injections but large scale producers who participate in the market as price makers must forecast their production for the next day. Wind forecast is produced by the TSO for the whole system and its regions; in addition wind farms with a Maximum Export Capacity (MEC) more than 10 MW have to measure wind speed and direction, air temperature and pressure and make those signals available to the National Control Centre (NCC).

Balancing. The balancing price consists of three components: -i) capacity payment (10% of the total); -ii)ex-ante (day ahead) energy price (about 30%) and post-ante price if wind farms participates in a market as price-maker. In case it operates as a price-taker it gets its energy price, changing on a half-hour basis.

Real time operation. In case of a dangerous situation for the network, the TSO may curtail wind production. A rebate for the wind production eventually curtailed is foreseen but there is no policy on this yet.

Frequency control. The Wind Farms with Maximum Export Capacity more than 5 MW under normal frequency ranges (i.e : A= 49.5 - B= 50.5 Hz) must operate with an active power margin of some 5% of the available active power. If the frequency falls below A= 49.5 Hz, the frequency response system must ramp up the wind farm active power output up to 100% of the available active power at 48 Hz. Where the system frequency is below/above the normal range and is recovering back towards the normal range, the frequency response system must act to ramp up/down the active powering according a prefixed law. The "normal frequency range "setting" of the points A and B may be different for each wind power station (WPS) according to the system condition and WPS location. Settings are controlled by the NCC.

WPS have no obligations in the secondary frequency control

Voltage control. WPS should operate at a given power factor, or operate at a voltage set-point. WPSs should be capable of operating at any point of a reactive/active power defined diagram; various solutions have been provided by independent wind power producers based on different types of wind turbine generation technologies: -i) constant speed WT, complimented by switchable capacitor banks; -ii) variable speed WT: no additional reactive power compensation, since they are fully controlled to be able to provide necessary voltage support.

If WPSs are being connected in areas where no other generation is available, additional reactive power support could be needed.

WPS should have a continuously acting Voltage Regulation System (VRS) with similar response characteristics to a conventional Automatic Voltage Regulator (AVR), to regulate the voltage at the connection point by continuous modulation of the WPS's reactive power output.

All grid connected WPS that had been connected after the lifting of the moratorium (July 2004) or the issuing of further offers on new WPS connections, have their voltage control functionalities in place, but not all are commissioned yet.

Fault Ride through capability (FRTC). Analysis of actual faults and simulations on the Irish power system show that voltage dips below 15% occur in vast areas, All WPS connected to the Transmission system should comply with a FRT Capability curve. No fee is paid to the producers for WT having this characteristic. It is not clear if a retrofitting of the old machines is compulsory.

Italy

Main characteristics of the system. Italy is a huge importer both of primary energy and electricity. In 2006, its Gross Electricity Consumption (GEC) was 359.7 TWh with a net import of 44 TWh. Italy has a wholesale electricity market (IPEX) and a Transmission System Operator (Terna) fully unbundled from the previous utility ENEL. Electricity and gas are under the control of an Independent Regulator. In 2006, the gross production of RES in the electricity sector was 52.1 TWh. Energy production by hydro and geothermal facilities production is almost saturated, notwithstanding a leading position in Europe. The Italian wind association ANEV reported that at the end of 2007 Italy had 2,726 MW of wind capacity installed with an increase of 623 MW in respect to the 2,123 MW of 2006. According to the TSO Terna the gross production was 4.14 TWh with an increase of 1.17 TWh with respect to 2006. ANEV anticipates that Italy could have 5.8 GW of wind generation capacity installed by 2010, which should produce about 10 TWh.

Targets of the proposed RES Directive. The RES target of the new RES Directive by 2020 for Italy has been indicated as 17% of final forecast energy consumptions (154.4 * 17%= 26.7 Mtep), starting from the 2005 level of 5.2% of the final consumption of 137 Mtep (6.71 Mtep = 4.29 Mtep Electricity + 2.12 Mtep Heating & Cooling + 0.30 Mtep Biofuels). Such target is considerably higher than the theoretical potential of the country (20.97 Mtep) communicated by the Italian Government to the EU in September 2007 [8.6]; which would corresponds only to 13.5% of the total energy consumption Even the theoretical potential of the electric sector indicated as a production by RES of 104 TWh (8.96 Mtep against 50 TWh = 4.29 Mtep of 2005), is a maximum which seems more "theoretical" than realistic.

As mentioned in par 2.1, for the sharing of the 20% overall target the Commission did not utilize the MS' national resource potential to produce renewable energy. On the contrary, the presence in the individual burden sharings, in addition to the flat rate for all MSs, of a portion evaluated on the basis of the GDP has "worsened" the situations of the "rich countries", Italy included. Moreover, since the Members States have a relatively high "freedom" in subdividing their burden sharing, it is not improbable that the electric sector should be given the major share of the burden. By assuming a percentage increase of the demand of 1.3%/yr , corresponding to 427.1 TWh by 2020 and the objective for the electric sector evaluated in proportion (17%/20%) of the overall 34% target for the EU electric sector indicated in the EU Road Map for Renewable Energy, a production by renewable sources of 123.9 TWh would be necessary.

The targets, both for electricity RES and total RES, for Italy looks very challenging and there are views that they could be not realistic. In any case, an increase on the final costs for the consumers can be expected.

A basic issue to reach the 2020 RES target is the trading of import by the Guarantee of Origin (GO): the real possibilities are not clear at the moment, since the provisions proposed by the Commission allow a limited trade: the European Parliament and Council of Ministers are beginning their examination.

Mechanism of support and tariffs. In the 1990's, a Feed-in Tariff (FiT) mechanism was adopted, called CIP 6/92. ENEL had to purchase the energy produced by new privately-owned power plants based on RES and from "assimilated sources" (CCGT, having an efficiency higher than a pre-established value). The selling price was based on the "avoided cost" (capital, O&M, fuel) of ENEL's generating capacity plus technology-related incentives, to be paid for 8 years. Capital and O&M cost were indexed to the RPI and the fuel cost to the price of natural gas.

In March 1999, it was ruled that the new Independent System Operator should purchase the "CIP 6/92 energy" and resell it on the free market to the captive consumers, at discounted prices. The difference between the purchase cost and the income from sales is charged to all

consumers through a related supplement (designated as A3). The total cost of this surcharge is huge, about 11.6 €/MWh on the final consumption in 2006.

In 2002 the CIP6/92 mechanism was eliminated and Green Certificates (GCs) were introduced, awarded to the new renewable plants, "qualified" by the TSO (GC_{IAFR}) and to production of the CIP6 renewable plants commissioned after April, 1, 1999 (GC_{CIP6}). Each Producer/Importer has a Green Certificates Obligation (GCO) to inject in each year "n" a "green power", in a percentage X% n-1 of its "subjected brown" production/import En-1 of the previous year "n-1". The first GCO in 2002 was 2%, then increased by 0.35%/yr in the period 2004-2006. GCs, not technology-related, were valid for 8 years from the date of commissioning; they are tradable through an exchange run by the Market Operator or through bilateral contracting between developers/importers. The value of the GC is typically added to that of the commodity energy, sold in the wholesale market or through bilateral contracts.

Over the years various criticisms have been made of the GCs mechanism: -i) There are too many exemptions to the production/import submitted to the GCO; -ii) "Brown" energy producers recover the costs of the GCs through a "markup" on their offers in the wholesale market, which influences the system marginal price and generates a sort of windfall profit for all energy production; -iii) Despite promises, the GCs price does not achieve a "market based" result. Up until 2004, the energy related to the GC_{IAFR} was not sufficient to cover the GCO. The remaining energy was therefore provided by GC_{CIP6} renewable plants, sold by the Gestore Sistema Elettrico (GSEl) at an administratively fixed price, so creating an artificial link to the "old" CIP6 mechanism. Due to the increasing presence in GC_{CIP6} of technologies with the higher incentives (e.g. biomass, municipal solid waste) and the indexing to the natural gas price in the avoided cost, the administrated price of green certificates increased from the 97.4 €/MWh in 2004 to a potential 137.5 €/MWh in 2007. It is worthwhile to mention that the Regulator ruled (Rule 249/06) a new computation for the component "fuel avoided cost" (gas) in the price of the CIP6 sales to the TSO: this resulted in a lower price of the avoided cost and correspondingly a lower "administrated price" of the GCs of the GSEl. After various recourses to the Courts, in January 2008 the Council of State confirmed the Rule of the Regulator: the decrease of the fuel avoided cost result is evaluated top be some 12.4 €/MWh, correspondingly the 2007 "administrated price" is expected to decrease to 125.13 €/MWh. In the pasts, all bilateral deals were based on such a "reference price", since producers have always seen it as a "top reference price"; -iv) It was claimed that the GC mechanism was particularly favourable to wind developers, while insufficient for other renewable technologies; v) Delays of the Government in fixing the long term obligation percentages made the projects less able to obtain financing..

In late December 2007, the Government in the Financial 2008 statement (Law 244 24 Dec 2007) ruled a revised GC process based on: -i) different values for each GC according to the renewable technology; -ii) utilization of feed in tariffs for solar PV; -iii) new "administrative" price for the GCs issued by the GSEl, no longer tied to the old "CIP 6" mechanism: GC price = [180 €/MWh - average price paid in the previous year by the Distributors to the producers for the so called "dedicated sale", equal to the price paid by the Distributors to the SB for their supply]. Since the SB, on its turn, has various supplies (market, import, discounted CIP 6 energy…) the corresponding price at which it sells energy to the distributors is in average lower than the wholesale market price: for 2007 about 67 €/MWh against 71 €/MWh. Accordingly, the new GC administrative price for 2008 will be 112,88 €/MWh; -iv) GCO on the "brown" (production + import) increased by 0.75%/yr from 2007 up to 2012, that is from 3.05% in 2006 up to 7.55% in 2012; -v) From 2008 until obtaining the EU target of 25% of RES with respect to the internal electric consumption, the GSEl will purchase from the RES developers the GCs "offered" exceeding the obligation at the average price mentioned above.

In addition to the above mentioned restructuring of the GC's mechanism, the plants with capacity lower than 1 MW have now the option to make recourse to very interesting "feed-in-tariffs". The overall process has been well accepted by the RES industry.

*Dispatching priority and balancing***.** Wind-powered generating resources have been assigned a dispatch priority. Wind production is not subject to the existing "two prices imbalance system" (i.e. payment according to pool market price or to balancing market price, according to the relationships of the single imbalance vs. the total zonal imbalance) applied to the thermal units. The wind generation imbalances are valued always according to the zonal pool price in the day ahead market and passed to the consumers. The wind plants with capacity less than 10 MVA do not have the obligation of sending a production schedule, while those with capacity greater than 10 MVA have the obligation of providing a production schedule. At the end of 2007, the Regulator established a new "incentive regulation" for the TSO, creating premiums and penalties aimed to improve the TSO's forecast of the wind energy production.

Fault Ride through Capability, frequency and voltage control. After a system study, in late December 2007 the Italian Electrotechnical Committee (CEI) issued a new "Technical Rule" devoted to the wind plants. This rule requires new wind turbines to have a low voltage ride through capability, down to a voltage of 0.2 Vrated. It also requires adjustable power factor at 0.95 leading to 0.95 lagging at the generator terminal. Each wind turbine is required to have a static characteristic of primary frequency control, for over frequency from 50.3 Hz to 51.5 Hz with droop adjustable from 2 %-5 %; moreover, its power output gradient during start up conditions is limited to a value of less than 20 %/min). Each wind turbine is required to provide active power control on request or by remote control signal from the TSO.

At the end of he 2007, with its Rule D 330/07 the Italian Regulator required to the Italian TSO Terna to produce, within March, 31, 2008, a report indicating which of the provisions of the mentioned CEI Technical Rule should be included, with an appendix, into the grid code. Furthermore Terna was asked to present within May 31, 2008 another report indicating the potential wind capacity which could be installed in the various areas where the impact on the system security could be potentially higher due to poor meshing of the grid (Centre South) or due to poor interconnection with the Mainland (Sicily, Sardinia), with the assumption that the yearly wind energy to be eventually modulated should be "reasonable" in relation to the potential not constrained yearly output. For the modulated energy, a rebate based on the spot price of the day ahead market is anticipated.

Presently, the available Terna's the medium-term projections for the development of wind capacity, against an installed capacity of 2656 MW (370 in Sardinia and 668 MW in Sicily) are: -i) 5000 MW within 2009 (650 MW in Sardinia and 1100 in Sicily) - ii) 7600 MW within 2011-2012 (800 MW in Sardinia and 2000 MW in Sicily). For the existing plants, in order to keep suitable security margins, Terna indicates that some 90 MW and 100 MW should be retrofitted with FRTC respectively in Sicily and Sardinia, while all the "future plants" to be commissioned after the issuing of the appendix of the grid code related to the wind plants, shall be equipped with FRTC. Concerning the gradual injection of the wind power into the network, while no prescription is mentioned for the existing plants, all "future plants" in Sicily, Sardinia, Centre-South should be equipped with the limits on the power output gradient.

Summarizing, at the moment of writing Terna anticipates that while for the existing plants the retrofitting with FTRC could be limited in Sicily and Sardinia, the introduction of all the characteristic indicated in the CEI technical rule in the new "future plants" is anticipated.

New Zealand

Main characteristic of the system and RES. The main production by RES (25.9 TWh) is obtained by hydro (22.8 TWh) and geothermal (2.8 TWh). Presently the wind energy is limited to 0.6 TWh.

There are no targets for RES by 2010.

Mechanism of support and tariffs. There are *no specific mechanisms to support* RES.

However, in late 2007 the Government released its Energy Strategy for 90% of electricity generation to be renewable by 2025. The three state-owned generating companies are not permitted to build new base load thermal generation for 10 years, and in December it was announced that legislation would be introduced to extend this to private companies. In both the Energy Strategy and the planned legislation the limits on thermal generation carry the provision "except to the extent required to ensure the security of New Zealand's electricity supply". In New Zealand, rather than the presence or absence of a RES supporting mechanism, the biggest issue is the transmission pricing methodology. Those advocating distributed generation state that New Zealand should adopt support mechanisms used in other countries. Regulations are soon to come to streamline the application process for connecting distributed generation. The distributed generation needs to pay for any incremental upgrade of the distribution network, and is paid for any deferral in distribution upgrades or reduction in transmission charges. A transmission pricing methodology, approved by the Regulating Authority, determines which the shallow connections are. Deep connections are paid by the wind plant developer. It is still being debated if the existing grid investment test needs to be modified or not because of increased renewable generation.

Dispatching. Wind production in theory has no priority, but does in practice. Any generation bids into the market; non-dispatchable generation, such as wind offers at either zero or one cents/kWh. Generation wishing to offer at zero price ("must run") participates in a "must run" dispatch auction. If successful, the generation can offer at zero price; if not it must offer at non-zero price and faces the risk of not being dispatched. The issue in New Zealand is the priority of hydro and wind generation when it comes to "spilling" if there is too much generation offered.

Scheduling and balancing. The requirements for wind generators are the same as for other generators, with generation offers 24 hr, 12 hr and 2 hr in advance of real time. Wind generators, when dispatched are paid the nodal market price. There are no special rules for balancing wind production: balancing is done as part of the reserve for normal load variation. The cost of balancing is paid by the consumer at large and will come as a part of frequency keeping costs and will also cover load variability and ramp rate mismatches between generating units changing dispatch levels.

Real time. No special measure, wind is treated as other generation and may be dispatched down to keep the circuits loading at secure levels. There are no rebates for any form of generation limited/curtailed.

With a high level of wind penetration, changes such as Wind Farms Cluster Management will likely be required. Generally speaking charges are based on "causer pays": so overheads specific to wind farms are likely to be paid by the wind generators.

Frequency control. Frequency regulation is supplied through an ancillary service market. So in principle, a wind plant with the ability to "spill wind" could offer in this service and be paid for it like other generators. However, wind plant generally increase balancing requirements, so they are likely to pay increased costs, rather then receive a rebate.

Voltage control. The obligation is maintaining voltage set-point and contributing to the voltage management following a contingency.

Fault Ride through Capability(FRTC). FRTC is compulsory for all generators greater than 10 MW. There are not rules specifically relating to wind. Wind plants that cause additional costs (e.g. additional reserves to cover the loss of the wind plant during events are required to pay the additional cost). Wind farms can provide "equivalence" to FRTC , such as contracting an equivalent amount of load for automatic shedding in the event that wind plant has no FRTC. There can also be "dispensation" to a degree and for a duration determined by the System Operator. There is no compulsory retrofitting, but the wind farm must be brought up to standard (or be disconnected) when the dispensation is withdrawn.

Spain

Main characteristic of the system and RES. The Electricity Act of 1997 implemented the "Regimen especial de generacion electrica" related to the development of the renewable production. Then a first "Plan de Energia Renovables" had targets for 2010 which have been modified with revisions in 2002 and 2005: it had a very important impact on the Spanish energy policy. During 2008 the evaluations for a new "Plan de Energias Renovables" for the period 2011-2020 will start. Spain is the second country in the EU, in terms of installed capacity and energy by wind sources. In 2007 a study was started for the evaluation of the wind energy that can be integrated by the grid: the related results will be the basis for the network planning in the span time 2007-2016.

Mechanism of support and tariffs. The incentive system established by the Real Decreto 436/2004, was based on FiT mechanism, with two options for the Producers to sell their production to the Distributors at fixed tariff or to the market, with a bonus linked to Average Regulated Tariff (ART). A very important change in the mechanism took place in 2007 after a long debate between the Government and the wind producer's association. In-fact Spain "corrected" the previous mechanism, with a new Real Decreto 661/2007, maintaining a transitory period until 2012 for the existing plants commissioned under RD436/04 not to change their conditions immediately. The possibility to sell the renewable energy both to he distributors or to the market was kept. However, the previous linkage with the ART in the "market option" was abandoned, since it was no longer possible to "transfer" the increasing cost of the generation component of the ART (due to increases in the price of the oil, natural gas) to renewable production. A "cap" and "floor" on the total price paid (market price + premium) were introduced, with a premium that can be modified according to the value of the pool price. ART, premium, cap and floor are updated every year, with an annual factor (RPI-X), taking into account both the Retail Price Index and an "efficiency factor" X %. The value of X has been set equal to 0.25% until 2012 and equal to 0.5% from 2013 on. In correspondence of the (RPI-X)= 3.35% valid for the period 2008/2007, the ART augmented from 73.228 €/MWh in 2007 up to 75.681 €/MWh in 2008, the maximum premium for wind production increased from 29.291 €/MWh in 2007 up to 30.272 €/MWh; the "cap" from 84.944 €/MWh up to 87,79 €/MWh and, respectively, the "floor" from 71.275 €/MWh up to 73.663 €/MWh in 2008.

From fulfilments of targets, every four years (next term 2010) the levels of ART, premiums, cap and floor will be revised for the new plants. Concerning the existing plants, only the new level of premium will affect them, while they will keep the previous ART, "cap" and "floor".

Balancing. The costs of balancing are on the wind Producers, for both options of sale to the Distributors or to the market. The difference is based on the method of presenting the hourly schedule, either 30 hrs before the day for sale to the Distributors, or in case of sale to the market 24 hrs before the day of the market. In both options a penalty, with respect to the market price, occurs if the deviations of each plant are contrary to the system needs. In such a way, at equal FiT, the revenues are higher for the producers having greater ability to follow the predicted schedules.

Fault Ride through capability. FRTC is compulsory for new plants, commissioned after 1 January 2008, while for the previous plants the rebates ruled by the RD 436-04, (paid for 5 years and 3.8 €/MWh in 2007 corrected yearly with the said mechanism of RPI-X) are kept.

Wind Farms Cluster Management (WFCM). Wind farms greater than 10 MW have the obligation to be connected (with costs on the Wind developer) with a Control Centre. This, on turn is to be connected to the National Renewable Energy Centre (CEGRE), on turn connected to the TSO center of REE. Geographically distributed wind farms are aggregated to Wind Farm Clusters (one cluster for each T system node). The concept of the WFCM is to be able to control each node of the high voltage transmission network, and to be able to adopt network control strategies related to active power reductions/curtailments, reactive

power/voltage regulation of the wind farms, active gradient control… Not all the Producers have technical/economical capability to create their own control centre: in this case, they can contract the services of someone else's control centre. The WFCM (f.i Iberdrola, Acciona) monitor/controls wind farms connected to each cluster node; the WFCM at level of CEGRE exchanges signals with the WCCM at Producer level to monitor/control all wind farms connected to each cluster.

Among the various wind producers/developers, Iberdrola has in operation since July 2003 a very advanced Center (CORE) which monitor/controls all the Iberdrola wind farms in Spain and abroad and the wind farms of other producers which have contracted the corresponding services.

Reactive/Voltage control. There are instructions/obligations for the power factor requirements, depending on the tariff periods of the year. The mechanism allows to receive additional rebates or to pay penalties. Therefore the mechanism can result in additional revenues for those producers who are able to follow the "official" needs of the system, which benefits from individual actions.

U.S. Texas (ERCOT)

Main characteristic of the system and of the RES. In the U.S., as for cumulative totals, Texas surpassed California in 2006 and leads the nation with 4,356 MW of installed wind generation [3].

In the ERCOT grid in Texas, which is asynchronously interconnected via HVDC links to the Eastern Interconnection and to the Western Interconnection, almost 94% of the total renewable capacity is wind. Texas' current Renewable Portfolio Standard (RPS) mandates 5,880 MW by January 2015 and meeting this target should not be a problem.

In addition Texas has a further target of 10,000 MW by January 2025.

Support to the RES and tariffs. The obligation to purchase renewable energy through Renewable Energy Certificates (RECs) in Texas falls on the Retail Electricity Producers (REP) (i.e. the distributors). Only the competitive REPs are obligated to meet the mandate. Other entities, e.g. municipal electricity utilities (Munis) and electric co-operatives (Co-ops), who are not part of the competitive retail market, are not subject to the mandate. The RPS is expressed in terms of installed capacity (unlike many other states which express the mandate in terms of percent of total energy consumed). The annual MW mandate amount must be converted to a MWh (i.e. REC) equivalent, through a Capacity Conversion Factor (CCF). For 2006 the CCF was 27%, which is relatively low for wind generation and was due to transmission constraints in wind generation areas. The CCF for 2007 has been set by ERCOT at 32.2%; it is expected that CCF will increase to about 35% as improvements in the transmission system are completed.

Normally each MWh of renewable production receive one REC. However, recent changes in regulations now award all non-wind renewable resources (e.g. solar) a "credit multiplier" of one RECs more in addition to the normal REC, making a total of two RECs for each MWh of production.

ERCOT established the first electronic certificate tracking system for renewable generation on 2001.

A revision of the State's RPS in 2005 directed the Public Utility Commission of Texas (PUCT) to establish the concept of Competitive Renewable Energy Zones (CREZs), which are geographic areas in the state where new wind development is likely to take place and for which transmission will be provided by a transmission owner, under a plan developed by ERCOT and approved by the PUCT. The amended Texas RPS also authorized the PUCT *to order* a utility to construct or expand transmission to meet Texas RPS. The development of

the CREZs has entailed a very public process with active participation of all stakeholders (PUCT staff, developers, transmission owners, REPs and environmentalists. The overall process has taken over 8 months so far, with completion scheduled sometime later in 2008.

Dispatching. ERCOT does not distinguish between energy produced by wind and that produced by conventional thermal generation. Transmission congestion is a real problem. ERCOT has the right to re-dispatch units to alleviate transmission overloads. In today's ERCOT market, each wind farm must submit an estimate of its production for the next day, which can be updated right up to the operating hour. In the new ERCOT nodal market design, to be operational in late 2008, ERCOT will prepare a wind-generation forecast for each wind resource using data supplied by each wind farm. The wind farms will not be forecasting their own output but they will provide site-specific meteorological and turbine status data to ERCOT.

There is not a formal obligation for ERCOT to justify the need for curtailment of wind farms. However, because of the cost involved, ERCOT market participants closely monitor ERCOT actions and can raise questions when they think that ERCOT is not operating the system properly.

8.5 Conclusions

1. All the Regions have targets, and related support systems, for the development of the Renewable Energy Sources (RES).
   In Europe the rules are dictated by the European Community Directives. In addition to the present one in force, which sets a 21% indicativ*e* share of electricit*y* produced by RES in the whole Community Gross Electricity Consumption (GEC) by 2010, with national indicative burden sharing for Member States, on 23rd January 2008 the EU Commission proposed a new "Renewable Directive" that establishes a binding target of a 20% share of RES measured as a percentage of final energy consumptions in the sectors of electricity (RESE), heating & cooling (RESH) and transportation (REST) by 2020. The Commission also established national binding targets in line with the overall 20% target.
   In the U.S. mandatory Renewable Portfolio Standards (RPS) have proliferated and have been created in 26 states, which together with Federal tax incentives, state renewable energy funds and voluntary green power markets are increasingly motivating RES development. To meet existing state RPS policies it is estimated that over 60 GW of new renewable capacity may be needed by 2025 in various states: however, non-hydro renewables would provide a modest 6% of total projected electricity generation by 2025.
   The U.S. Congress considered a number of *Federal* RPS proposals; the U.S. House of Representative passed a Federal RPS bill but it was unable to pass out the U.S. Senate.
   In Canada and in Australia there are various Federal and Provincial directives. In New Zealand, notwithstanding the absence of specific mechanisms, the Government has a strategy for obtaining 90% of electricity production from RES by 2025: generating companies are not permitted to build new base-load thermal generation for 10 years.

2. In Europe, the Parliament and the Council of Ministers are discussing the proposal of the EU new RES Directive. One key issue is the mechanism of the RES Guarantee of Origin (GOs): the present provisions allow trading only by governments and not companies and virtual trade is not permitted with non-EU countries. The association of European electric companies EURELECTRIC strongly criticizes in a position

paper the proposed restrictions on GO trading and asks for amendments so as to facilitate cross- border trade and help to meet the challenging EU RES targets.
In the U.S. state RPS policies differ: states have adopted different eligibility rules related to geographic location and electricity delivery. Reliance on unbundled Renewable Energy Certificates (RECs), in some aspects similar to the European GOs, for state RPS compliance has been linked to the development of regional electronic certificate tracking system to issue, record, track and retire RECs. The completion in 2007 of two new regional tracking systems, brought to five the regional tracking system in the U.S. and correspondingly most RPS states have opted to allow, with restrictions, the use of unbundled RECs for compliance purposes. RECs are traded in markets and also imported from Canada.

3. Wind production is fundamental in reaching the RES targets. In Europe, the most common support scheme is based on feed-in tariffs. Germany and Spain are the countries most favourable to this system, which for them has been very efficient, particularly for the wind development, with respectively 20.6 GW and 11.6 GW of installed capacity at the end of 2006. The Green Certificates (GCs) scheme adopted in some European countries has been fine tuned/revised recently in Italy and in UK. In the U.S. of the 8,900 MW of non-hydro renewable capacity additions from 1998 through 2007 occurred in states with RPS programs, 93% came from wind.

4. Values of the feed in tariffs and of the GCs/RECs are different worldwide. This is caused by regional factors, such as physical geography, population density, and regulatory process which in some case may introduce considerable "shadow costs" if the process is not formally and in reality streamlined.

5. Discussions are arising world wide concerning the "integration" of the increasing wind production in the "traditional" power systems. The technical and regulatory solutions related are not the same in different countries, since the electrical system characteristics, the state of evolution of the electricity market and the percentage of penetration of the wind source is different. A unique and comprehensive solution for regulating, supporting and integrating RES in general, and in particular wind-powered resources, does not appear currently possible

6. Concerning *dispatching,* basically, if there is no grid congestion, wind injection has no scheduling obligation and it is taken "as it comes". In Canada, in Ontario and Alberta markets, wind resources are treated as price takers. In Australia currently there are non scheduled and scheduled wind plants in South Australia, were license conditions require new wind plants to register as scheduled generation, subject to the same dispatch requirements as other generators. In addition, to address network control issues it has been proposed to allow the implementation of semi-dispatch arrangements, under which semi-scheduled wind farms could be required to reduce output if necessary to manage system security. In Ireland large producers who participate in the market as price makers are supposed to forecast their production for the next day. In the U.S. ERCOT does not distinguish between energy produced by wind and that produced by conventional thermal generation and has the right to re-dispatch units to alleviate transmission overloads. In today's ERCOT zonal market, each wind farm must submit an estimate of its production for the next day. In the new ERCOT nodal market design to be operational in late 2008, ERCOT will prepare a wind-generation forecast for each wind resource using data supplied by each wind farm. The wind farms will provide site-specific meteorological and turbine status data to ERCOT, but the forecast will be done centrally through ERCOT.

7. Concerning *balancing,* under the responsibility of the TSOs, generally the costs are passed to consumers. In Canada those jurisdictions that have Transmission Tariffs based on U.S. FERC Order 888 provide energy imbalance as an Ancillary Service with no penalties. In other jurisdiction, some tariffs provide preferential treatment in

the form of larger bandwidth of scheduled versus delivered energy. In Australia, if scheduled wind plants and semi-scheduled wind plants contribute to imbalance through failing to follow dispatch targets, they can be required to contribute to regulation costs, through a "causer pays" arrangements. The off-shore and the new onshore wind plants in Denmark and all the wind farms in Spain can be considered "causer pays", even if with different details.

8. *Fault Ride through Capability* is generally mandatory for the new wind turbines, especially for injections in the transmission grid.
9. *Frequency regulation* by wind plants apparently is only required in Ireland; wind turbines greater than 5 MW must keep a 5% band margin of the available active power to regulate in a certain frequency range (e.g. 49.6-50.5 Hz). This is probably due to the small size of the Irish system and limited interconnection capacity. In other situations, e.g. Australia and Canada where there are ancillary service markets, such a situation, even if theoretically possible, is unlikely.
10. Concerning *voltage regulation,* in general wind plants should operate at a given power factor or at a voltage set point. In Ireland in some areas additional reactive power support could be needed. In Canada, if the wind plant is capable of providing additional capability and if the TSO finds this useful to avoid congestions or facilitate transactions, the capital cost of the reactive power is eligible for some rebate.
11. It is worthwhile to mention that in EU, EURELECTRIC take issues with the proposed grid-acces rules for RES Power. According to EURELECTRIC, all electricity producers should compete on a level playing field, paying a transparent and non-discriminatory cost for grid access and balancing.
12. Worldwide, transmission is recognized as among the most prominent barriers to the achievement of RES targets. States and grid operators are increasingly taking proactive steps to encourage transmission investments within the context of growing RES targets, and therefore of projected wind installations. This is often done under the pressure of regulatory bodies, which in some case allow higher rate of return WACC for the invested capital in new infrastructures.

8.6 References

[1] Directive 2001/77/EC of the European Parliament and of the Council on the promotion of electricity produced from renewable energy sources, Brussels 27 October, 2001

[2] Proposal (COM 2008)19def for a Directive of the European Parliament and of the Council on the promotion of the use of energy form renewable sources, Brussels, 23 January 2008

[3] AWEA market Report , January 17, 2008

[4] US Department of Energy
Annual Report on US Wind Power Installation, Cost and Performance Trends: 2006

[5] Ryan Wiser, Galen Barbose - Lawrence Berkeley National Laboratory
Renewables Portfolio Standards in the United States, April 2008

[6] Italian Government-Department of European Affairs
"Energy: issues and challenges for Europe and Italy
Position paper: 10 September 2007

ANNEXE: Summary Tables for chapter 8

	AUSTRALIA R.Lawson(NEMMCO); A. Baitch	NEW ZEALAND Alex Joosten - Transpower NZ	ERCOT (Texas) J.C. Smith(UWIG)-H.Durrwachter (Luminant) Warren Lasher (ERCOT)
Main System Data	**Data 2007**	**Data 2006**	**Data 2006**
Installed Capacity (MW)	46200	8400	79472
Total gross demand (TWh)	198,0	39,1	306,0
Total net demand (TWh)	174,0	37,7	290,0
RES (TWh)	18,1	26,0	7,1
RES % of Country on demand	9,1%	66,4%	2,3%
RES (MW)			4800 MW (2007)
EU RES obligation 2010, or others obligations/standards	Various laws of Federal (MRET) and State Government's Schemes (Queensland:GECs, New South Wales :GGAS; Victorian :VRET, South Australian).Wind projected by 2012: 7,6TWh	90% of RES by 2025	Renewable Portfolio Standard (RES) 5880 MW of RES in Texas by 2015 Meeting the Standard : not a problem
Country/Region wind capacity (MW)	689	171	3135 (2007)
Country Wind energy (TWh)	1,7	0,62	6,3
Wind hours of utilization (hrs) *	2467	3608	2023
"Average" real wind utilization (hrs) **	2820	No indication	2680
Wind production respect to demand	**0,9%**	**2%**	**2,1%**
Wind injection in T Net	80%	Na	100%
Wind injection in D networks	20%	Na	0%
Tariffs Type	**Quota system**. Electric retailers and wholesale buyers must acquire renewable energy certificates (RECs) from accredited renewable energy generators or "displacement sources".RECs are traded in separate mtks.The number of RECs that liable parties must purchase is bases on their share of national energy Cost of the support mechanism: not paid by the consumers by an explicit supplement but "captured" by increases in the wholesale cost of energy.	No specific mechanism to support RES. To respect the 90% of RES by 2020, GenCos not permitted to build new base load thermal stations for 10 yrs Regulations to come for connecting distributed generation. Wind generators offer at zero or 1 c/MWh in the mkt and are paid the nodal price No quantitative figures indicated	**Green Certificates (GSc**); validity 3 years. Obligation **only** on competitive DisCos. **Not** on Munis & Coops! Present % respect to demand= 2.5%, slight increase up 2015 GCs identical for on shore and off shore, **not** for other RES No degression or indexing for the value of GCs **No GCs mkt: bilateral deals plant owners & other parties** **C**ompetitive **R**enew. **E**nergy **Z**ones, where **new** WFs to be sited established with public study involving all stakeholders. Developers pay only radial connections; T net provided by T owners

(*) The annual capacity factor is only indicative since some of the new capacity is installed during the year.
(**) Average hours of utilization for the capacity installed since the beginning of the year

	France EdF Jerome C Duval	Spain-REE David A. Baeza	Italy L. Salvaderi
Main System Data 2006			
Installed Capacity (MW)	115000	82336	92811
Total gross demand (TWh)	478,4	268,0	337,8
Total net demand (TWh)	446,4	Na	316,4
RES (TWh)	66,0	48,1	52,1
Renewable EU obligation 2010 (*)	**21%**	**29,4%**	**25%**
RES % of Country on demand	**13,8%**	**18,0%**	**15,4%**
Respect of EU target	**"Far from Committment"**	**"Good chances"**	**"Far from Committment"**
Country wind capacity (MW)	1500	11239	2123
Country Wind energy (TWh)	2,2	23,4	3,24
Hours of utization (hrs)	1467 (average observed 2200)	2082 (average observed 2300)	1536 (range 1200-3000 hrs)
Wind production respect demand	**0,5%**	**9%**	**1,0%**
Wind injection in T Net	0%	Na	Na
Wind injection in D networks	100%	Na	Na
Tariffs			
Type	Feed In Tariffs (purchasing obligation for WF<12 MW and for WF also > 12 MW in ZDE (Few call of tenders)	a) Average Regulated Tariff b) OMEL+ bonus : "cap and floor"	a) Old plants: FiT Avoided cost+ incentives 8 years b) New plant= GCs + Market price
Onshore	Total period : 15 years; 2 periods 1^ period: 10 years full premium 82 €/MWh constant 2^ period: 5 years; degression based on productivity, down 28 €/MWh last year	Validity 20 years a) 73,228 €/MWh 20 years 61,20 €/MWh rest of life b) OMEL + 29,29 €/MWh cap = 84,944 €/MWh floor = 71, 275 €/MWh	a) CIP 6 = (100,6 + 61,3) €/MWh b) GC from 2002: mechanism criticized GC mechanism restiled since 1.1.2008 GC paid for 15 years Different values of GC for various techs Renewable Obligation: + 3,5%/yr up to 2012
Off shore	Total period : 20 years; 2 periods 1^ period: 10 years, full premium 130 €/MWh constant 2^ period: 10 years,degressive, down 30 €/MWh	b) OMEL + 84,3 €/MWh cap = 164,0 €/MWh floor = NA	New "administared price of GCs decoupled from old "CIP6" mechanism Incentive regulation for TSO prediction of wind injection

(*) EU Communication 24th November 2006 " Progress in renewable electricity

	Denmark-Energienet	Germany
Sheet 1	**Rikke.B.Gaardestrup- Mogens R. Pedersen**	**Carsten Leder (RWE)-Yvonne Sassnick (Vattenfall**
Main System Data 2006		
Installed Capacity (MW)	12680	125000
Total gross demand (TWh)	36,1	540,0
Total net demand (TWh)	33,5	Na
RES (TWh)	9,6	74 (only 51.7 TWh subsidized)
Renewable EU obligation 2010	**29%**	**12,5%**
RES % of Country on demand	26,6%	13,7%
Respect of EU target (*)	**"Perfect on track"**	**"Perfect on track"**
Country wind capacity (MW)	3436	20454
TSO wind capacity (MW)	75%Eltra - 25% Elkraft	NA
Country Wind energy (TWh)	6,1	30,8
Hours of utization (hrs)	1775	1506
Wind injection in T Net	70%	0%
Wind injection in D networks	30%	100%
Tariffs		
Type	**Feed In Tariffs, linked to the mkt price**	**Feed In**.Validity 20 yrs, two steps: 5 + 15 yrs
	(low purchasing price: market+CO2 premium; capped)	Each step: - .2%/yr since 2004
Onshore	Future: mainly tied to (2005-09) "**SC**rapping & repowering	2006 first step : 83,6 €/MWh for 5 yrs
	Various cathegories; some are :	2006 second step : 52,8 €/MWh for 15 yrs
	* WT < 1999 &< 10yrs: Fixed price (80 €/Mwh and 57 after full hrs	In 2007: 81.9 €/MWh for 5 yrs
	* WT < 1999 & > 10 yrs: Elspot+ premium + *balancing fee*	2007 : 51,7 €/MWh for 15 yrs
	Premium :0-13,3 €/MWh, linked to monthly Elspot price	No indexation to RPI
	[Elspot+ premium]: capped to 48 €/MWh (360 DDK/MWh)	
	* WT from 2000 to 2002: Elspot + subsidy (57) until full hrs	
	After full hrs: Elspot	
	* **New WT** commissioned > 1.1.2005:	
	No SC: Elspot+premium (13,3) +*balancing fee (3.07)*	
	With SC: Elspot+premium (13,3) +*balancing fee (3.07*)+ **SC**	
	SC= 0-16.1 €/MWh, linked to monthly Elspot price	Plant in operat< 2010 get higher tariff for 12 yrs
	[Elspot+ +premium++ SC] : capped to 64 €/MWh	Annual digression from 1.1.2008
	Balancing fee : 3.07 €/MWh, compensating the costs	2007 : higher 91,0 €/MWh; basic :61,9 €/MWh
Off shore	**Tender Procedure**	2008: higher =89,2€/MWh; basic 60,7 €/MWh
	Elspot+ result of the tender (Horns Reef : 518 DDK for 12 yrs)	2011: higher = 57,1 €/MWh; Basic = 57,1 €/MWh
	Existing 424 MW . New tenders:400 MW	TSOs to pay connections for WF < 31.12.2011
		political decision to limit socialized cost

(*) EU Communication 24 th November 2006 " Progress in renewable electricity

	IRELAND Ivan Dudurych - Eirgrid	Canada D. Jacobson
Installed Capacity (MW)	5836 (without wind)	125365
Total gross demand (TWh)	27,8	605,0
Total net demand (TWh)	24,8	557,0
RES (TWh)	2,7	18,0
Renewable EU obligation 2010	**13,2%**	**NA**
RES % of Country on demand	9,7%	3,0%
Respect of EU 2010 target (*)	**"Good chances"**	**NA**
Other non EU targets 2010		**6000 MW**
Country wind capacity (MW)	693	1534
Country Wind energy (TWh)	1,62	2,9
Hours of utization (hrs)	2340	2628
Wind injection in T Net	50%	
Wind injection in D networks	50%	
Tariffs		
Type	**Feed In Tariffs** Validity 15 yrs- Indexed to the RPI	**Feed in tariffs:** different in various states British Columbia = 65-79 C$/MWh, indexed to RPI + 3,05 C$/MWh if Ecologo certification Ontario= 110 C$/MWh; 20% indexed to RPI+ 3,52 C$/MWh Contracts term = 20 yrs
Onshore	Not different from inland and offshore wind farms, but slightly higher for small (< 5 MW) wind farms Large (> 5 MW) : 57 €/MWh Small (< 5 MW) = 59 €/MWh Biomass (landfill gas)= 70 €/MWh Hydro & orher biomass = 72 €/MWh	Green Pricing programs, with Renewable Energy Credits which can be exported to the U.S. The value of RECs varies between 9-90 C$/MWh, with 20 C$/MWh as typical
Off shore		No offshore installation: Potential in BC (1500 MW) and Great Lakes (700 MW)

(*) EU Communication 24th November 2006 "Progress in renewable electricity"