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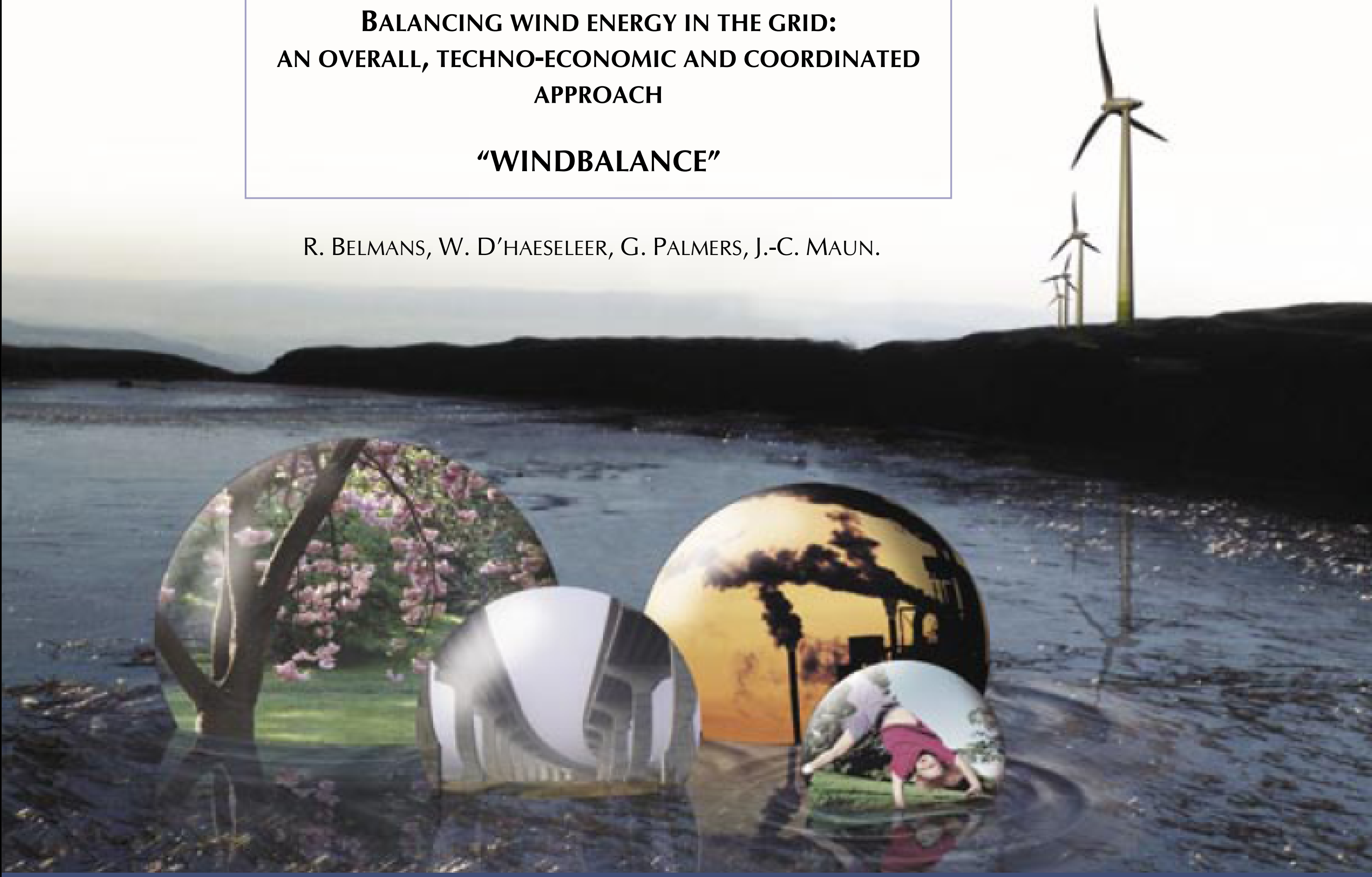
SCIENCE FOR A SUSTAINABLE DEVELOPMENT

BALANCING WIND ENERGY IN THE GRID: AN OVERALL, TECHNO-ECONOMIC AND COORDINATED APPROACH

"WINDBALANCE"

R. BELMANS, W. D'HAESELEER, G. PALMERS, J.-C. MAUN.



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(SSD)

Energy

FINAL REPORT PHASE 1

BALANCING WIND ENERGY IN THE GRID: AN OVERALL, TECHNO-ECONOMIC AND COORDINATED APPROACH

"WINDBALANCE"

SD/EN/02A

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January 2009

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R. Belmans, W. D'haeseleer, G. Palmers, J.-C. Maun. ***Balancing wind energy in the grid: an overall, techno-economic and coordinated approach "WINDBALANCE"***. Final Report Phase 1. Brussels: Belgian Science Policy 2009 – 50 p. (Research Programme Science for a Sustainable Development)

Contents

1. Introduction

1.1 Research context[1]

Wind energy can make an important contribution to reaching the Belgian target for renewable energy sources (RES) imposed by the European Commission (Directive 2001/77/EC) and thus to sustainable development. However, since wind power is variable and predictable within limits, the participation of wind energy in markets must always keep in mind that security of supply should not be compromised. This is another European imperative for governments, regulators and network operators (proposal for a directive COM(2003)740). Finally, supporting wind energy has to be done in a manner compatible with the internal market, a third requirement of the EC (Directive 2003/54/EC).

Together with (imported) biomass, wind energy is the renewable energy source with the highest potential in Belgium now, although in the long run, photovoltaic systems may become important. The challenges faced when integrating wind energy into the grid where described by ETSO (2005). The grid issues can be summarized as more complicated ancillary services, required grid extensions and system adequacy and stability problems.

To ensure a continuous and reliable grid operation, generators and system operators have to supply services that are generally denoted as "ancillary services". These deal with frequency and voltage stability, transmission security, black-start capability and economical manageability of the grid. In order to provide these services, reserve capacity is necessary to maintain the balance in the grid. Ancillary services do not directly deliver net power, but are a necessity for the secure and reliable operation of the electricity system. In Germany for example, by 2015 at the latest, about 20% (=7000 MW) of the installed wind capacity of 36.000 MW has to be provided as balance power (ETSO, 2005). This amount increases significantly with on-going wind capacity installation.

Another barrier to the development of wind energy is imposed by the electricity grid. The connection of wind turbines may require grid reinforcements. New wind farms are often built far away from the main load centers. New overhead lines therefore become necessary to transport the electrical energy to where it is consumed. The intermittent contributions from wind power must be balanced with other back-up generation capacity located elsewhere, which adds to the requirements for grid reinforcements. This raises the overall investment cost of the wind farm. In the DENA grid study (2005) this is illustrated for Germany. It is shown that the government's goal of at least 20% of RES in power generation in Germany between 2015 and 2020 is achievable. However, this would require the upgrading of approximately 400 km of the existing 400 kV grid and new construction of approximately 850 km. Consequently, the additional costs for the expansion of wind energy will cost German private households between 0.39 and 0.49 Cent € per kWh in 2015, not taking into consideration the problem of social acceptance of overhead lines and the delay that this undoubtedly will cause in system build-up.

Finally, wind farms behave differently from conventional power plants with respect to grid stability. In case of a fault in the grid causing a voltage drop, conventional plants normally continue to generate power by which they support the system stability, while wind farms tend to shut down and worsen the existing stability problem. Also voltage instability may be caused by a high reactive power demand of certain types of wind turbine generators. However, these problems are today addressed

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[1] Research context, targets and methodology described in section 1 are based on project proposal [1].

by specific requirements in local grid codes . They oblige wind generators to stay connected during certain voltage drops .

Clearly, the potential for wind energy is limited by different technical limits of on one hand the grid, and on the other hand the ability of the Transmission System Operator (TSO) to maintain the balance in the grid with the reserves at his disposal. However, within these technical limitations, the potential for wind could be influenced by other interventions than technical adaptations. Since electrical energy cannot be stored directly, it is the task of the TSO to maintain the balance between supply and demand in the grid at all times. Therefore, the amounts of energy that will be injected in or withdrawn from the network must be estimated beforehand by the TSO. Consequently, market participants must predict their future generation or consumption. At a given instant in time, designated as "gate closure", all market participants have to submit their intended consumption/generation schedules for the next period to the TSO. At gate closure, the control over the power system is passed to the TSO. Market participants no longer have the opportunity to correct differences between their expected generation/consumption and their actual physical position by trading with other market participants.

One of the issues hampering the grid integration of wind is the fact that day to day forecasts of power generation from wind energy are possible only to a limited extent. Changes in wind forecasts are an important factor causing differences between predicted and actual generation. Such deviations are being intercept by the TSO, restoring balance by activating contracted balancing services. However, this services are not free and charges are being transferred to the market participant responsible for the imbalance. Consequently, the amount of time between gate closure for a period and the start of that so-called "settlement period" (mostly between a quarter of an hour and an hour) is an important factor influencing the development of wind energy. Gate closure close to the start of the settlement period allows wind farm operators to include more accurate wind predictions in the generation schedule they submit. As a result, deviations from this schedule will be smaller and so will the imbalance in the grid caused by wind energy, which increases the maximum wind capacity that can be integrated in the grid. Furthermore, this reduces the imbalance cost and avoids the use of "special" market conditions for wind energy. It increases the value of generated wind power, again increasing the incentive to invest in wind energy.

Wind can best be integrated in the power system if it becomes integrated in the market environment. Since the market as it exists today has emerged in the period of a concentrated market (with central power plants in largely public or regulated ownership) it is not adapted to decentralized generation. With current market rules wind power can difficultly enter these markets as they are today. Since a large share of wind energy is supposed to become integrated in the future, benign conditions for wind power are necessary for its participation in the market. In recent years, several initiatives were taken to develop offshore wind farms in the Belgian area of the North Sea. However, the capacity of wind that can be installed in the Belgian grid, as in other countries, is limited due to such market barriers but also technical limitations.

1.2 Research targets

The general objective of the WindBalance Project is to identify technical and market barriers limiting the wind potential in Belgium, and to analyze how they could be removed. Also, the contribution of wind energy to ancillary services is a main point of discussion and research in all the aspects (technical, economic, environmental…). Consequently, with the results of this project, Belgian policy makers will be able to take the necessary actions to increase the potential of wind energy.

In a first phase of the project, the final goal was to develop a simulation tool for a single wind farm. With this tool, market revenues for wind power would be calculated for different market rules utilizing synthetic time series of wind power output and associated prediction error. Revenues for wind power were to be calculated as a function of time in the following sequence:

- *Nomination; the wind power producer offers an amount of nominated markets at different time scales (long term, day ahead, intraday).*
- *Imbalance calculation; calculation of remaining variations in available predictions or variations in generation/demand).*
- *Imbalance settlement: if possible imbalance will be settled on a closure.*
- *Final imbalance: if not all imbalance can be settled this will lead to inconsistency for imbalance is calculated according to the TSO's imbalance tariff.*

This tool was developed with the results from three previous tasks also falling under the first phase of the project. In a first task an inventory and description of all market rules concerning the production of wind energy in Belgium has been made. Second, stochastic descriptions of wind power output and wind power prediction error as a function of prediction horizon were composed. Additionally different nomination scenarios were selected (day-ahead, one time intra-day, rolling intraday). In combination with the stochastic descriptions of wind power and prediction error this lead to a stochastic description of wind power and its variation for different time scales. The final task necessary before constructing the simulation tool beheld the stochastic description of market prices. This has been developed, based on historical prices from the Belgian Power Exchange (Belpex) since it was operational (21 November 2006).

In the second part of the project, the technical and economical aspects of wind energy in the electrical energy market will be combined. Consequently, the approach in this second phase is twofold. Firstly, the upper limit for the aggregated wind power potential in a national and international context was quantified, accounting for technical, regulatory and economical boundary conditions (phase 2). Second, possibilities to facilitate the integration of wind by adapting the market mechanisms involved are looked at (phase 3).

The second phase of the project used a top-down approach: the aggregated wind power potential in Belgium is studied. This potential is limited by several constraints, which are studied in this part of the project. Step by step, a model was build to evaluate these constraints. In a first task (task 5.1) a model was built making following three major assumptions:

- Only the control zone of the Belgian TSO Elia is considered, containing Belgium and a part of Luxemburg.
- Network constraints and potential grid bottlenecks are not considered. This is a reasonable assumption when considering the Elia control zone only and a limited amount of wind power.
- All available power plants are used in a cost-optimal way to cover demand in the Belgian control area. Consequently, initially, the effect of the liberalized market, with several active generators, is not considered. Generation units are deployed in the most cost-optimal way, as if they would be operated by one central party.

Under these assumptions, the technical upper limit for wind is determined by the capacity of the other available generation units to set off the fluctuations in the wind energy production and the potential active demand side management. The cost of this approach will be assessed as is the impact on greenhouse gas emission.

However, within Belgium, the potential of other generation units to balance the intermittent output of wind farms is limited. This barrier could be relieved by considering the whole of Europe in a second task (5.2), while still making abstraction of potential grid bottlenecks. Now, Belgium is not considered as an island anymore and interactions with the rest of Europe are discussed. This allows for a more realistic approach of the integration of wind power in Belgium since the aggregation of different system positively affects the integration of wind power.

The assumption that no bottlenecks are present in the Belgian and European grid clearly is an enormous simplification of reality. Therefore, in the final task of phase 2, this assumption is dropped and grid constraints are added to the exercise. This will reduce the maximum potential for wind capacity. Under different assumptions, the maximum amount of wind power that can be integrated in the grid will be quantified. A possible approach is to define different scenarios to achieve the Belgian RES-targets in terms of certain percentages of wind energy. It can then be examined whether the generation park obtained is tolerable for the TSO. Naturally, this maximum wind capacity identified is not an established fact. Expansion and reinforcement of the grid to enable the connection of more wind is possible, at a certain cost. The necessary investments in the grid and the indirect cost of the altered operation (e.g. increased congestion complicating a free electricity trade) are identified.

The linkage between Task 5 and Task 6 will be made in the third phase of the project, allowing for a more correct analysis of wind power in the operation of the Belgian system. After briefly examining the adequacy, the total operation of the Belgian electricity generation system can be studied. Introducing a high level of detail for the operation of the elements and connection between them in the system, in-depth analyses of the integration of wind power can be made. Not only the cost and greenhouse gas emissions are investigated but also the reliability of the entire system is taken into account. This way, policymakers gain understanding of the technical consequences of different options regarding the introduction of wind farms in the Belgian transmission grid, and the associated network investments required.

1.3 Research methodology

In order to facilitate the integration of a significant fraction of wind energy into the power system wind energy will need to participate in the markets for energy and ancillary services aside from the specific support mechanisms such as the sales of tradable green power certificates. Taking into account characteristics such as being variable and not entirely predictable, market rules strongly affect the feasibility of such a power source to participate in the different markets.

In the first phase of the total WindBalance Project, the behaviour of wind energy as a market participant was modeled in a bottom-up approach. For this purpose a market simulator that is able to model the behaviour of a single wind farm in different power and ancillary service markets was constructed. This market simulator serves as a tool for determining the prices that wind power can yield in the different markets under different market conditions and depending on the predictability of the wind power output. The simulation tool was developed as follows:

- The rules on power and ancillary service markets in Belgium were inventoried and those specifically affecting wind power were determined. These market rules form a set of boundary conditions for the simulation tool.
- The feasibility of wind energy operators to deliver power at market conditions was described statistically. The stochastic distributions of wind power output and error of wind power predictions are the input for the simulation tool.

- As an approximation, prices at power markets are considered not to be affected by wind power. The stochastic distributions of market prices serves as second input for the simulation tool.

Simulations of wind energy in power markets was finally performed for different markets (over the counter, day-ahead, intra-day/balancing markets). Different markets can be allocated to different products and gate closure times. Similarly, wind power predictions can be performed with different prediction horizons and the prediction error is typically reduced with a decreasing horizon. Therefore, the simulation was carried out for different time scales reflecting the different market gate closure times and wind prediction horizons and the associated market prices and prediction errors.

The developed tool will serve for parametric sensitivity studies as to be carried out in the final phase of the project in combination with the aggregated power system simulator developed in phase 2. In this second phase, the power system is modeled as a whole where unit commitment in the centralized, hence, dispatchable fraction of the Belgian power generation park is modeled. By incorporating the different constraints of the Belgian system in a model, the different parameters influencing the integration of wind power in this system can be examined.

A Mixed Integer Linear Programming (MILP) approach is adopted. The MILP model defines the most cost-optimal way for meeting demand with the available generation capacity. The electricity generation system is simulated for 24h. The GAMS software, using the commercial CPlex solver is linked to Matlab and Excel [2],[3] en [4]. The model is extensively discussed in [5]. Figure 1 gives a graphical representation of the model structure.

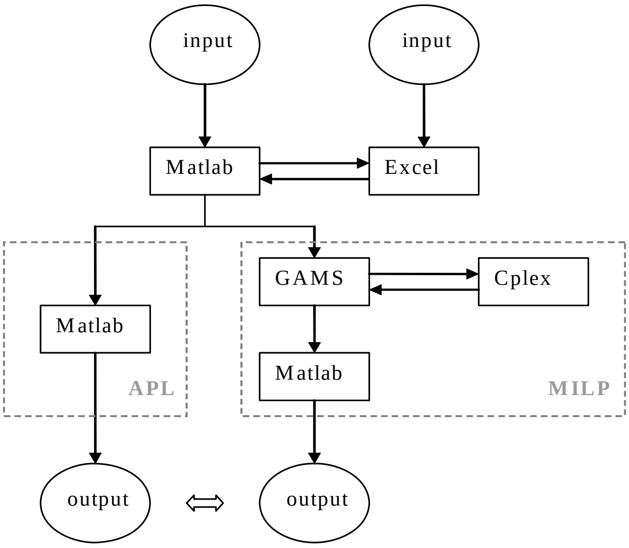

Figure 1: Schematic overview of model implementation .

The two elements that define the intermittency of wind power, namely variability and unpredictability, are examined in the simulations. The integration of increasing amounts of wind power is evaluated in the Belgian system for four different wind speeds and an equal amount of demand profiles. On the one hand, the fluctuating wind speed profiles illustrate the variability over time. On the other hand, to illustrate the uncertainty, a distinction is made between a Unit

Commitment (UC), based on forecasted data, at the start of the 24h period and a dispatch for every hour based on the actual wind power output. Discrepancies between forecast and actual output need to be addressed by the available power plants, which depend on the choices made during UC. Both variability and uncertainty of wind power induce costs. Not only the actual costs to the system but also the opportunity costs are addressed.

Combining this top-down approach with the bottom-up approach of phase one will finally lead to a third phase where economic possibilities to integrate wind energy into the global system will be analyzed.

2. Bottom-up research (phase 1)

2.1 Requirements for the participation in power markets in Belgium

2.1.1 Wind power integration support

To promote the integration of RES-e in Belgium, a system of green certificates together with a priority dispatch has been opted for. The latter means that green electricity must be sold before all electricity generated by conventional power plants must be sold. This ensures maximal renewable output but also increases the pressure for balancing services. In certain cases, the Belgian TSO has however the possibility to curtail offshore wind power in order to guarantee stability of the grid. 60% wind output can be curtailed by the Belgian TSO (Elia) without giving a compensation, if more has to be curtailed, producers are compensated for their lost green certificates[2] [6].

The intention of the green certificates' system is to rise the share of renewable energy in the total electricity production by other means than subsidies. In this system, the producers of renewable energy have certificates at their disposal. These certificates are then transferred to the buyers of that green electricity. They have to meet a certain quota of these certificates facing a penalty if not attained. The implementation of such a system has important consequences for the production of renewable energy. The federal and Flemish governments have developed a scheme requiring system operators to purchase green energy certificates at a fixed minimum.

Under the Royal Decree of 16 July 2002 on the establishment of mechanisms aimed at promoting electricity generated from renewable sources, Elia as the transmission system operator is required to purchase green certificates from renewable energy producers. The certificates are issued by CREG (Commission for Electricity and Gas Regulation), VREG (Flemish Electricity and Gas Regulatory Body), CWaPE (Wallonia Energy Commission) and IBGE/BIM (Brussels Institute for Management of the Environment). The minimal price for this being 107 € /MWh for offshore and 50 €/MWh for onshore wind energy. Under Article 25 of the Flemish Electricity Decree, distribution system operators must purchase green certificates from generators whose facilities are connected to their network for at least 80 €/MWh (only onshore). This means that Elia only buys certificates from generation facilities connected to the Elia grid in Flanders at voltages of between 70 and 30 kV. The generation facilities must not be more than 10 years old [7].

In Wallonia, all green power generation units must submit a prior application to CWaPE (Walloon Energy Commission) for the issuance of green certificates. A certificate of origin issued by an approved inspection body must be attached to this application. Once this preliminary application for certification has been accepted by CWaPE, the producer supplies its quarterly energy metering statements to CWaPE. On the basis of these statements, CWaPE issues a given number of green certificates. Once in possession of the green certificates, producers may sell them to any purchaser, regardless of physical power sales. Each quarter, power suppliers must return to CWaPE a quota of green certificates proportional to the quantity of power supplied. A fine per missing certificate is levied. A system imposing the repurchase of green certificates by the transmission system operator (Elia) at a minimum price is also imposed by the Federal Government. Green certificates purchased by the TSO are then resold on the green certificate market.

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[2] Paragraph 1 & 2 coming from De Vos, K. & Driesen, J. "Balancing management mechanisms for intermittent power sources: a case study for wind power" unpublished

2.1.2 Balancing responsibility

The access holder, being a generator or a consumer, must designate a BRP (Balance Responsible Party) for each access point. The BRP may be a generator, a major consumer, an energy supplier or a trader. The BRP contract sets out the balance-related rights and obligations of the TSO (Elia) and the BRP. Elia must ensure that balance is maintained within the control area, whilst the BRP is responsible for maintaining balance between total injections and total off-takes at its access points for each time period of 15 minutes. The BRP must provide the TSO with an access schedule of all its injections and off-takes (known as nominations) for every time period the next day and this must be send before a specific time (gate closure which is 14h00 in Belgium). The following information must be supplied:

- Expected injections and off-takes (generation and consumption);
- Nominations for power exchanges between BRPs;
- Import and export nominations at the borders of the control area.

ELIA informs the BRP on Day D-1 before 18h00, whether BRP's day-ahead nominations are confirmed or not and what are the reasons for possible rejections. ELIA will also, communicate the possible incremental or decremental adaptations asked in order to manage congestions concerning the injections at the access points,.

The BRP's full portfolio of nominations must be balanced on a quarter-hourly basis but it also important that real-time power flows correspond to this nominated balance. However, due to the difference between the accuracy on the northern and the southern borders, a positive quarter-hourly imbalance between injections and off-takes limited to maximum can be accepted [8].

2.1.3 Imbalance settlement

Using metering and nomination data, the TSO checks, for every 15 minutes if the BRPs are maintaining their balance. If an imbalance is found in the balance perimeter of a BRP between total physical injections, import and purchases on the one hand and total off-takes, export and sales on the other, an imbalance tariff is applied. This tariff is calculated based on the applicable balancing mechanism (Table 1).

The imbalance price is based on the prices that Elia charges for balance settlement in the Belgian regulated zone. If a BRPs imbalance reduces Elia's control energy requirements, the imbalance price is calculated according to the reference market price (Belpex). Imbalance price data can be consulted on the website of Elia [8].

Table 1: Imbalance settlement fee (source: Elia)

		Net regulation volume	
		Net downward regulation	***Net upward regulation***
ARP imbalance	**Positive**	Min[γ*GGA;GGA+δ*(MA-GGA)] ***(1)***	0,90 * ref. market price
	Negative	1,10 * ref. market price	Max[α*GGO;GGO+β*(MO-GGO)] ***(2)***

(1) 90% of the reference market price is also a minimum price
(2) 110% of the reference market price is also a maximum price

From 1 January 2007 until 30 June 2007:
$\gamma = 0{,}90$ if $GGA > 0$ and $1{,}10$ if $GGA < 0$
$\delta = \min(1; BAV/450)$
$\alpha = 1{,}10$
$\beta = \min(1; BOV/450)$

Dutch abbreviations and English descriptions:

BOV = gross upward regulation volume
BAV = gross downward regulation volume
NRV = net regulation volume
GGO = weighted average upward regulation price
GGA = weighted average downward regulation price
MO = highest upward regulation price
MA = highest downward regulation price

2.1.4 Balancing mechanism

As transmission grid operator, the key mission of Elia is to manage the balance of its control area. To achieve this, Elia has a number of resources at its disposal:

- Primary reserve;
- Secondary reserve;
- Tertiary reserve via contracted generation units;
- Tertiary reserve via shedable loads;
- Reserve contracts with neighbouring transmission system operators.

The purpose of the **primary reserve** is to stabilize frequency disruptions in the entire UCTE-zone. Serious frequency disruptions can result in automatic load shedding and in the worst case initiate a black-out. This reserves are automatically activated, have to respond between 0 to 30 seconds and are not longer used than 15 minutes. These reserves can be delivered to Elia by each connected party, if meeting certain technical specifications. They are remunerated with a fixed compensation, covering reservation and activation costs.

The secondary reserve has two components: a contracted secondary reserve and free bids of secondary control power. The contracted secondary reserve is subject to "secondary control contracts". It is assigned following an annual call for tenders amongst power generators established in Belgium. Those companies that are contracted to Elia must supply the reserve power specified in the contract when asked for by Elia and are remunerated for putting it at disposal. Each day they submit bids to Elia for the activation of that reserve. These bids go in pairs (upward regulation and downward regulation), must be in multiples of 5 MW and are within the limits set out in the graph below:

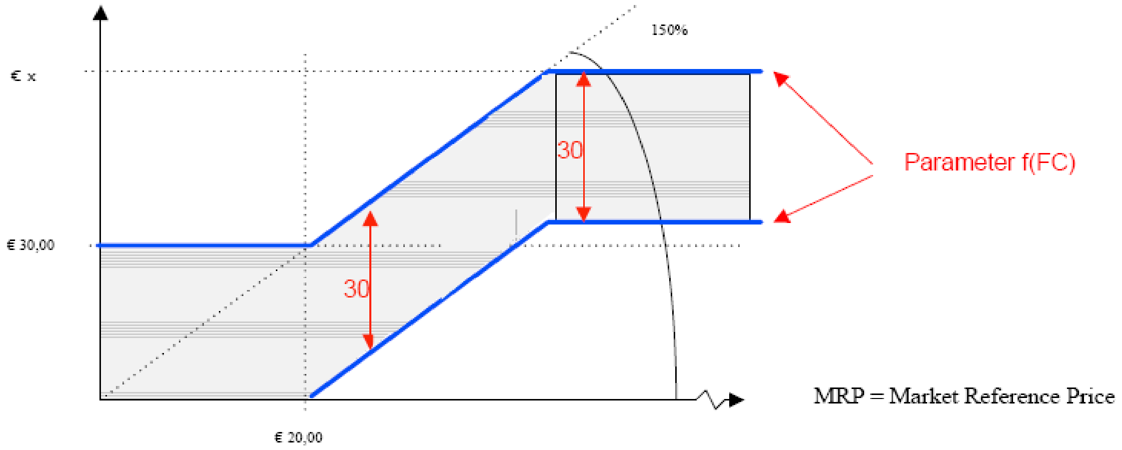

Figure 2:Bidding limits for secondary control powerwhere f(FC) = price determined in accordance with the price of fuel and the efficiency of the production units MRP = Market Reference Price = day ahead clearing price on the Belpex Energy Exchange (source: Elia)

If the bids go beyond these limits, Elia brings them back to the maximum/minimum value defined in the graph. Additional bids can be freely introduced on a daily basis, extra to any reservation contract, by power generators complying with the technical specifications required by Elia, whether or not they already have a contract with Elia or other generators who have the opportunity to supply additional control power. These bids are also introduced in pairs (up and down) and in multiples of 5 MW, but are not subject to any price limit. Bearing in mind that these bids are not subject to any yearly power reservation, Elia will only pay for their activation.

Communication of these bids (volumes and prices) for day D is made to Elia on day D-1 at 15h00 at the latest. Elia will select the bids on an economic basis until the required secondary control power level is reached, excluding beforehand certain bids problematic for the safety of the grid. The selection is made independently for upward and downward regulation. At the end of the selection process, the generators will be informed whether their bids have been accepted or not by Elia for the purpose of the secondary reserve. Bids, which are not retained for the secondary reserve, are added to the tertiary reserve bids within the framework of the contract for Coordination of the Injection of the Production Units (from now on, CIPU contract) (see below).

The **tertiary reserve via generation units** has two components: a contracted tertiary reserve and bids within the framework of the CIPU contract. The contracted reserve is subject to "Tertiary Reserve Contracts". It is assigned via an annual call for tender. Making this tertiary reserve available is remunerated. The activation prices for the contracted tertiary reserve are calculated on basis of a contractual formula taking account of the fuel price and the efficiency of the generation unit. Given its nature, this reserve can only be activated upwards.

Bids within the framework of the CIPU contract derive from the obligation incumbent on the generator to put at Elia's disposal, the power reserve (upwards or downwards) of each of his units. The bids from generators with regard to the activation of that power reserve are free upwards and downwards. They are positive for upward activations (Elia pays the generator for activation) and may be positive (the generator pays Elia for their activation) or negative (Elia pays the generator for the reduction of his production) for downward activations.

The **tertiary reserve via the shedable customers** is also contracted (Interruptibility Contract) via a call for tenders. It concerns industrial customers who must reduce their off-take below a contractual threshold at the request of Elia. The contract provides for only a limited number of activations per year. The remuneration price for one activation is equal to 110% of the price of the last bid activated upwards with a minimum of €75/MWh. Elia also has **reserve contracts with neighbouring TSO's** at its disposal. These contracts can be activated for importing or exporting power. Volume and price are defined and may be reviewed by the respective TSO's. They take into account the generation resources that can be activated (volume and price of activation) in the concerned control area.

To summarize, Elia has the following resources at its disposal to compensate for a negative imbalance in the area (BRPs inject less power than they take off):

- Secondary upward regulation
- Contracted tertiary reserve on the production units
- Non-contracted tertiary reserve on the generation units (CIPU Incrementals)
- Shedable loads
- Import of reserve power coming from neighbouring TSOs.

For a positive imbalance in the area (BRPs inject more power than they takeoff), Elia has at its disposal:

- Secondary downward regulation
- Non-contracted tertiary reserve on the generation units (CIPU Decrementals)
- Export of reserve power to neighbouring TSO's.

The various resources put at the disposal of Elia are activated on the basis of the bids submitted to Elia, by activating first the cheapest and then the progressively more costly bids (**merit order**), taking all types of reserves and parties involved together. Certain elements may be taken into account to modify this purely economic order:

- The high speed and automation of the secondary control compared to other bids that have to be activated manually by the operators;
- The presence of congestion on the grid making it impossible to activate certain bids from a grid security point of view;
- The limited number of activations allowed from the contracted reserve among the shedable customers.

The volume of bids activated depends on the volume of imbalance in the Belgian control area. The direction of its imbalance determines the type of bids to be activated (upwards if imbalance is negative or downwards if the imbalance is positive), the purpose being to try to keep the control area in balance all the time [7].

2.1.5 Balancing after gate closure

BRPs can also avoid any imbalance resulting from an unscheduled event like a breakdown suffered by an industrial customer or a power station by trading energy on the 'intra-day hub' on a same-day basis. BRPs submit their nominations to Elia before noon the following day. These nominations will:

- Be submitted before 01.00 pm on Day D+1;
- Contain, for each concerned ([ARP From], [ARP To]) pair, a power value for each quarter-hour of the day;
- Contain only positive values;
- Be submitted with a precision of 0.1 MW;

- Be consistent with the corresponding nomination submitted by the counter-party.

Elia takes the measurement data as a basis for verifying whether all BRPs are meeting their respective balance management obligations. Complementary with the intraday mechanism, BRPs can also pool their imbalances with other BRPs by signing a "Pooling Agreement". This means that Elia will invoice the global netted imbalance to one of the BRPs in the pooling agreement [8].

2.1.6 Electricity markets on Belpex power exchange

Belpex is a short term, physical power exchange for the delivery and off-take of electricity on the Belgian hub. Belpex facilitates anonymous, cleared trading in 3 different market segments, namely a day-ahead market segment (DAM), a continuous day-ahead market segment (CoDAM) and a continuous intraday market segment (CIM). Belpex' day-ahead market segment is coupled with its two neighbours, APX in the Netherlands and Powernext in France.

The Belpex DAM provides standardized products (hourly instruments) for producers, distributors, industrial groups, traders and brokers to sell and purchase electricity to be delivered the day after. The DAM closes at 11h00 on D-1. The characteristics of the Belpex DAM can be summarized as follow:

- Anonymous trading;
- Delivery on the Belgian hub via the Elia nomination system (Elia being the Belgian transmission system operator);
- One hourly trading periods and contracts;
- Standard order book Gate Closure;
- Short term, physical trading (e.g. via limit orders, block orders);
- Fixing of contracts via a double-sided blind auction;
- Clearing and settlement facilities provided by central counterparty.

The Belpex CIM provides standardized products (hourly and multi hourly instruments) for producers, distributors, industrial groups, traders and brokers to sell and purchase electricity on a continuous basis, and this up to 5 minutes before delivery. The characteristics of the Belpex CIM can be summarized as follow:

- Anonymous trading;
- Contract creation through continuous trading;
- Delivery on the Belgian hub via the Elia nomination system (Elia being the Belgian transmission system operator);
- Standard 1-hour, 4-hours and 6-hours products;
- Instruments available for trading as from 14:00 the trading day prior to delivery until 5 minutes before delivery;
- Market segment open 365 days/year, 24 hours/day;
- Clearing and settlement facilities provided by central Counterparty.
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2.2 Feasibility of wind energy operators to deliver power at market conditions

As mentioned in the introduction, current market rules in Belgium and technical limitations make it difficult for electricity from wind energy to enter the markets for electricity. However, properly designed power markets could have the potential to improve significantly wind power economics, and consequently enhance large-scale integration.

For this purpose, the value of wind energy in different power markets must be determined. Therefore, a representative model of wind power generation and the associated uncertainties is developed, by determining the stochastic behaviour of wind power output and of the prediction error as a function of the prediction horizon. A statistical bottom-up approach is used. Based on measured and predicted wind power production data, synthetic time series of wind power output and wind power prediction error are generated. These data must exhibit the same statistical characteristics as the input data in terms of their mean value, variance and autocorrelation. The method developed is based on a number of interesting publications on synthetic time series generation [11][12][13][14][15][16][17].

Publicly available historical wind generation data and the corresponding wind power prediction data from the German TSO control areas are used for calibration of the model. For the analysis, data from a number of Belgian wind farms have been used for comparison. Furthermore, any other empirical data can be used as well.

2.2.1 Markov Chains

With the available data, synthetic wind power time series are generated based on a first order Markov-chain approach. In this method the input data range is divided into a number of power output intervals. The historical time series is then analyzed by counting the transitions from one power output interval to another. Using these occurrences of the transitions, a 'Transition Probability Matrix (TPM')' is built, which contains the probabilities of transition from any power output interval to any other one. Often this matrix is also referred to as 'Markov Matrix'.

With the Markov TPM, synthetic time series can be generated based on a random process. For this end the cumulative form of the TPM (CTPM) is needed, which is a matrix in which each element is the sum of all preceding elements in the same row (including the element itself) of the Markov TPM. Elements in this CTPM represent thus the chance that, starting from the 'row power output interval', the next power output level will be smaller than the 'column power output interval'.

Synthetic time series are then generated through, starting from the initial power output level, determining the next one using a random number generator and the cumulative TPM. The next power output level is the one where the generated random number (between 0 and 1) matches the cumulative probability. This 'controlled random process' takes care that the transition probabilities are respected.

Since the generation is a random process and the generated series is not of infinite length, a condition is set that the mean, variance and autocorrelation of the generated series must lie within 5% of those of the input series. Generation of the time series is repeated until this condition is met.[3]

2.2.2 Gap Filling

When the input data contains gaps - as the German data does - the Markov method can also be used for gap-filling purposes. Here the input data for the Markov TPM generation is the largest continuous

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[3] When the generated series is long enough, e.g. longer than one year, this usually goes fast (< 3 times).

series that can be found, in order to have as much data as possible. For every gap a synthetic time series with the gap's length is generated, taking the value previous to the gap as the initial value for the time series generation. In order to correspond better with the gap properties (gap mean = average of previous and next value), each of these generated series is divided by its mean and then multiplied by the gap mean. This makes sure the filled gaps do not influence the characteristics of the input time series too much. The result for a gap in one of the German input time series can be seen in Figure 3.

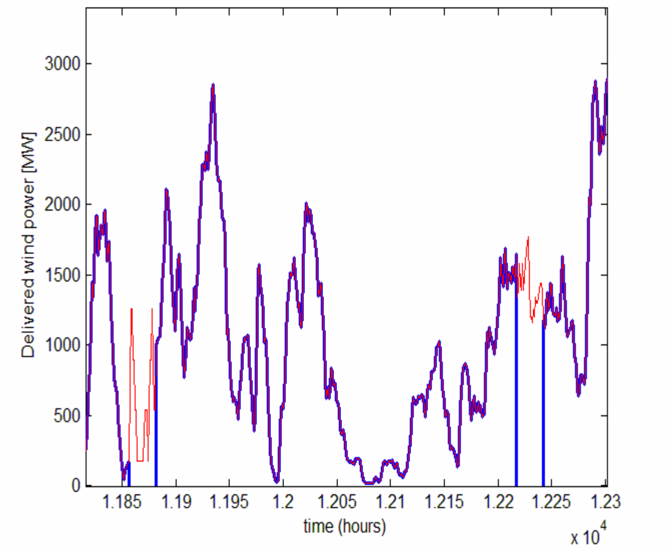

Figure 3: Illustration of gap filling (blue: series with gap, red: result)

2.2.3 Synthetic time series for wind power

To generate a synthetic time series for wind power output, the explained method is not sufficient. Firstly, following meteorological rules, wind speed and subsequently wind power are subject to important seasonal and even diurnal variations (figure 4a). These are not incorporated in the described method.

One possible solution could be to subtract a monthly mean from the input series before computing the Markov TPM. After generating the synthetic series (which now represent the variations on the monthly mean values), these monthly mean values can be added again. However, since wind power variations are larger with high output (e.g. in winter) this method will not fully deliver the desired results.

The seasonal variations are tackled by computing a separate TPM for each month. Each time a month of data is generated, the TPM of the next month is used for this month's time series generation. This way the statistical properties of each month remain present in the model, which allows for a more correct time series generation. To avoid disturbance of the model due to a possible exceptional meteorological month, the input should contain data of several years.

A consequence of this method is, however, that a discontinuity can exist between different months in the generated series. The reason can be that different power output intervals are used, or that there are too many power intervals or too little input data. This can indeed cause empty rows in the Markov TPM, creating difficulties with the transition from the last power output of the last generated month.

To reduce/eliminate this effect the same power output intervals should be used for each separate TPM, the input data series should be long enough and the number of power output intervals should be limited. When each row of each TPM sums up to one, discontinuities are avoided.

Diurnal variations are much smaller, and are therefore neglected in a first step. However, in a further step these can be taken into account e.g. by subtracting a sine function representing the daily variations before calculating the monthly TPM's, which is later added again to the generated series.

A second consequence is that the Markov chains do not account for the power spectrum of the input time series. When looking closely at Figure 5 and Figure 6, it can be seen that the generated series does not exercise the same variability as the input series although mean, variance and autocorrelation are the same. Possible solutions like higher order Markov chains, using higher-time-lag autocorrelation coefficients, or 'controlling' the random number generator with the power spectrum characteristics, would allow to decrease these deviations. However, they would also strongly increase the complexity of the generation algorithms and the consecutive tools. Therefore, they have not been implemented here.

2.2.4 Synthetic time series for wind power prediction (-error)

When historical data for predicted wind power output is available as well - as is the case with the German control zones data - it is interesting to generate time series for the wind power prediction too. This can be very valuable as input for several power and market models.

When generation of wind power prediction series would be done exactly in the same way as for the wind power generation, there would be no relation between the generated wind power and wind prediction. Therefore it is better to focus on the prediction error.

Generation of time series for the prediction error can be done in a similar way as for wind power. However, instead of diurnal and seasonal variations, here it is the dependency of the prediction error from the output power level that requires special attention. The prediction error will indeed be larger for higher power output levels, as can be seen in Figure 4b. (For the highest power levels the curve drops down again. We see 3 reasons for this. The mean reason is the fact that the power curve is flat at high power levels, leading to smaller variations in the prediction error. Other reasons are that there is less data for the higher power levels, and the fact that on full capacity the prediction can only be less or equal to the real production.)

This problem is tackled by a regime-switching approach. A separate TPM is used for different ranges of power output levels. For every transition, the TPM used to calculate the next value of the prediction error series is the one corresponding to the present power output level of the generated synthetic wind power time series. Again, empty-row problems in the Markov matrices can be avoided ensuring enough input data and a limited number of intervals.

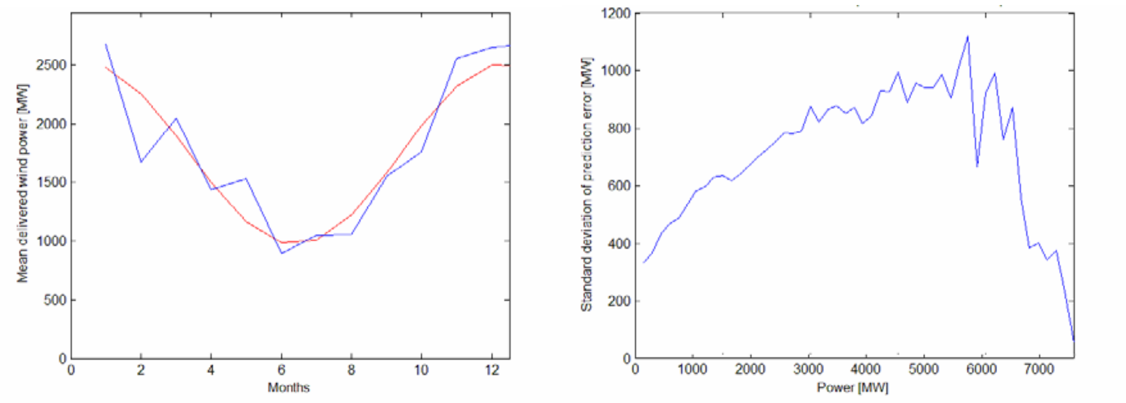

Figure 4: Mean monthly wind power values (4a, left), Standard deviation of prediction error for different power levels (4b, right)

2.2.5 Results

The results of this analysis are satisfying. The generated time series for wind power and for prediction error are very similar to the time series of the input data. This can be verified in Figure 5 and Figure 6. Of course these figures are not identical due to the synthetic character of the series in Figure 6. However, over the different months, both exhibit the same statistical properties in terms of mean value, variance and autocorrelation.

As stated above, there is still a slight difference in variability between the generated and the input time series. Possible solutions which can be further investigated in future research are mentioned.

The developed model can generate time series for wind power as well as for the prediction error, which is of importance for power and market studies. The model serves as well for a single wind turbine, for specific wind farms as for research projects for entire regions.

The results from this wind power time series synthesizer will be used as input for power flow studies and market and power system modeling, as in phase 2 of this project. When combined with the market data developed in task 3, the series generator will also serve to determine the value of a wind farm portfolio (task 4). Different nomination scenarios can be selected (day-ahead, one time intra-day, rolling intra-day) by adjusting the standard deviation of the input error, in order to simulate different power markets.

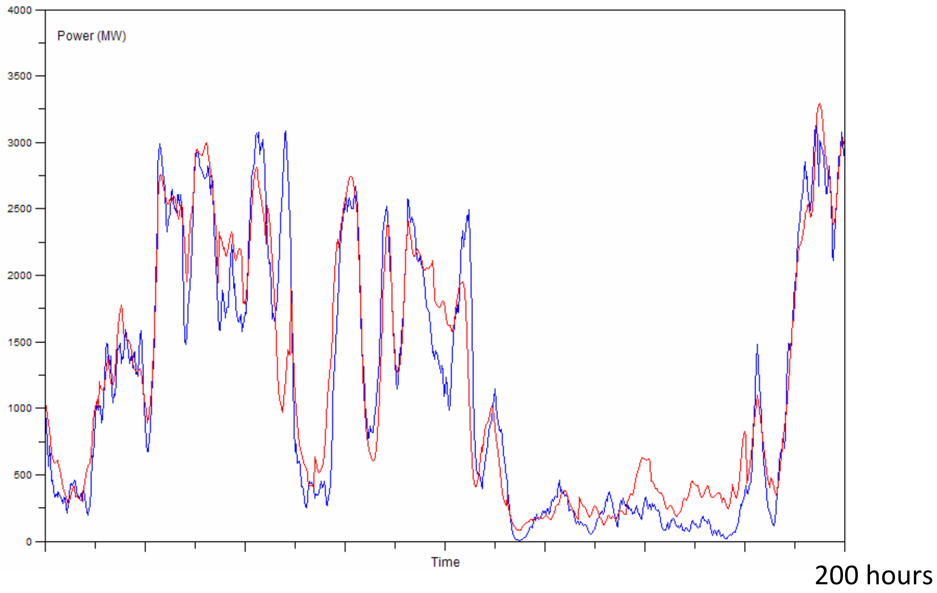

Figure 5: Input time series: wind power (blue) and predicted wind power production (red)

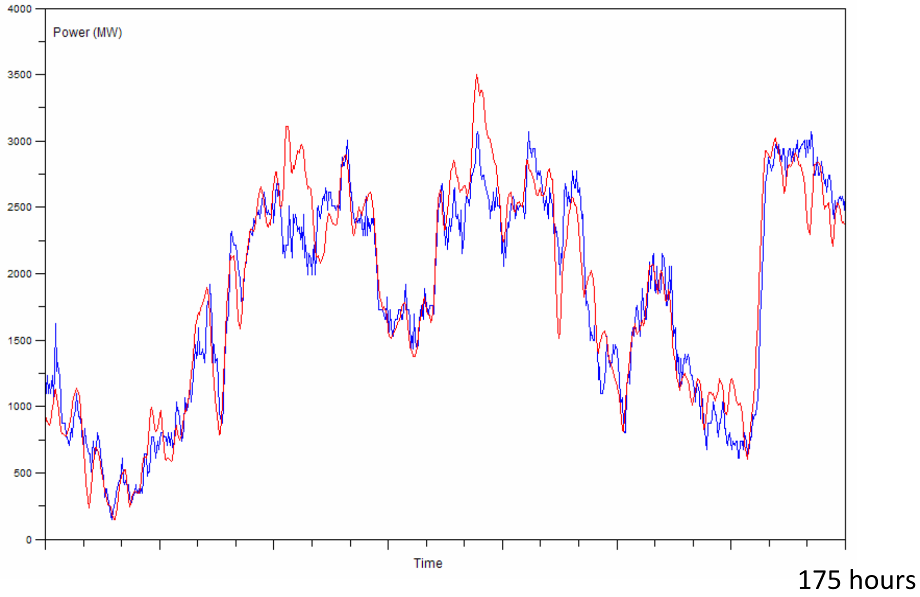

Figure 6: Generated time series: wind power (blue) and predicted wind power (red)

2.3 Characteristic market data

2.3.1 General considerations regarding the availability of market data in Europe

ETSO[4] recently published the results of its legal survey on market transparency, in which it verified the compliance of all ETSO members with the transparency requirements adopted in the recently published Congestion Management Guidelines[5] (CMG) and the ERGEG Guidelines for Good Practice in Information Management and Transparency in Electricity Markets[6] (GGP). While the CMG places binding obligations on TSOs and power exchanges because of its adoption into Regulation EC 1228/2003[7], the GGP is not legally binding and fulfils a pure advisory role. Amongst others, the ETSO survey focuses on balancing and wholesale market data. A summary of the main findings is contained in table 1 and 2.

Mainly column 4 in table 1 - considering the availability of average and marginal balancing prices - and column 4 in table 2 - considering the availability of wholesale market data of the past two years - can be helpful in the search for historical market data.

2.3.2 Availability of market data

Since this task aims to stochastically describe market prices[8] on the basis of historical prices from Belgium and the Netherlands, this section mainly focuses on the availability of market data in both countries. Besides, a quick glance will be taken at some other European countries.

2.3.2.1 Day-ahead spot market prices

- Belgium: Belpex (www.belpex.be)

The Belpex day-ahead market was successfully released on 21 November 2006. Only Registered Website members, i.e. parties having submitted a duly completed Registered Website member application form to Belpex, have access to historical market data (historical market clearing volume, market clearing price and indices as well historical aggregated curve data) and historical market reports (historical Daily, Weekly and Monthly reports).

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[4] ETSO, *Executive Summary – Legal Survey on Transparency*, May 2007, available on www.etso-net.org

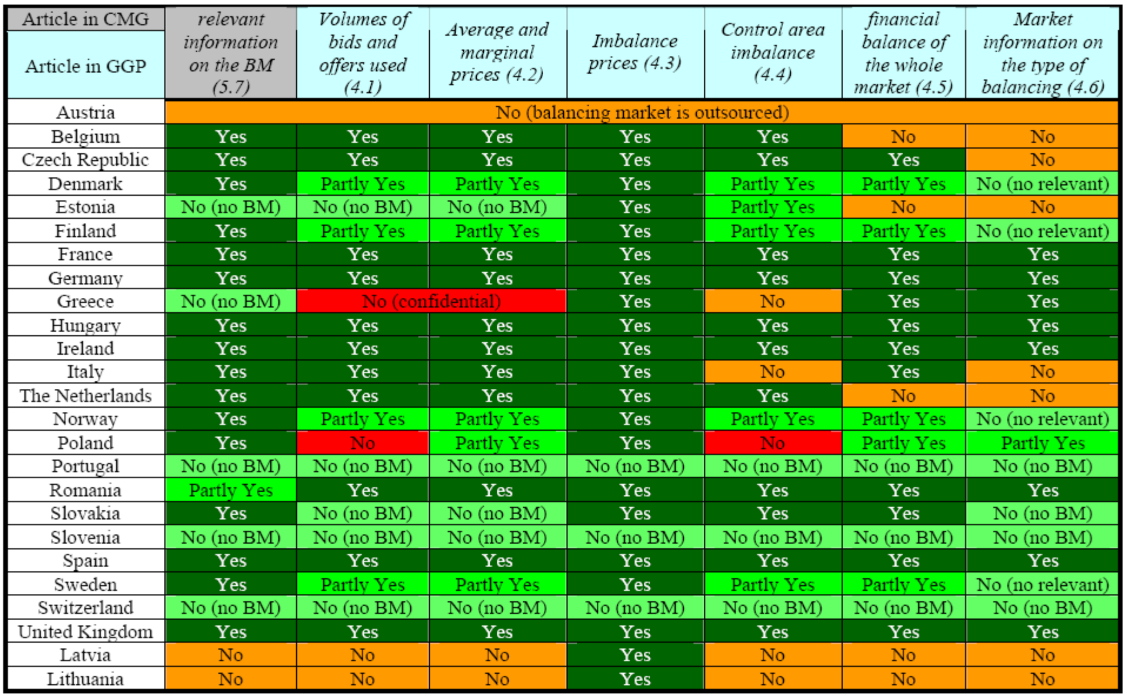
[5] European Commission, Commission Decision of 9 November 2006 amending the Annex to Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity, Official J. Eur. Union, L 312, 2006, 59-65

[6] ERGEG, *Guidelines for Good Practice in Information Management and Transparency in Electricity Markets,* 15 March 2006, available on www.ergeg.org

[7] European Commission, *Regulation No 1228/2003 of the European parliament and of the council of 26 June 2003 on conditions for the access to the network for cross-border exchanges in electricity*, Official J. Eur. Union, L 176, 2003, 1-10.

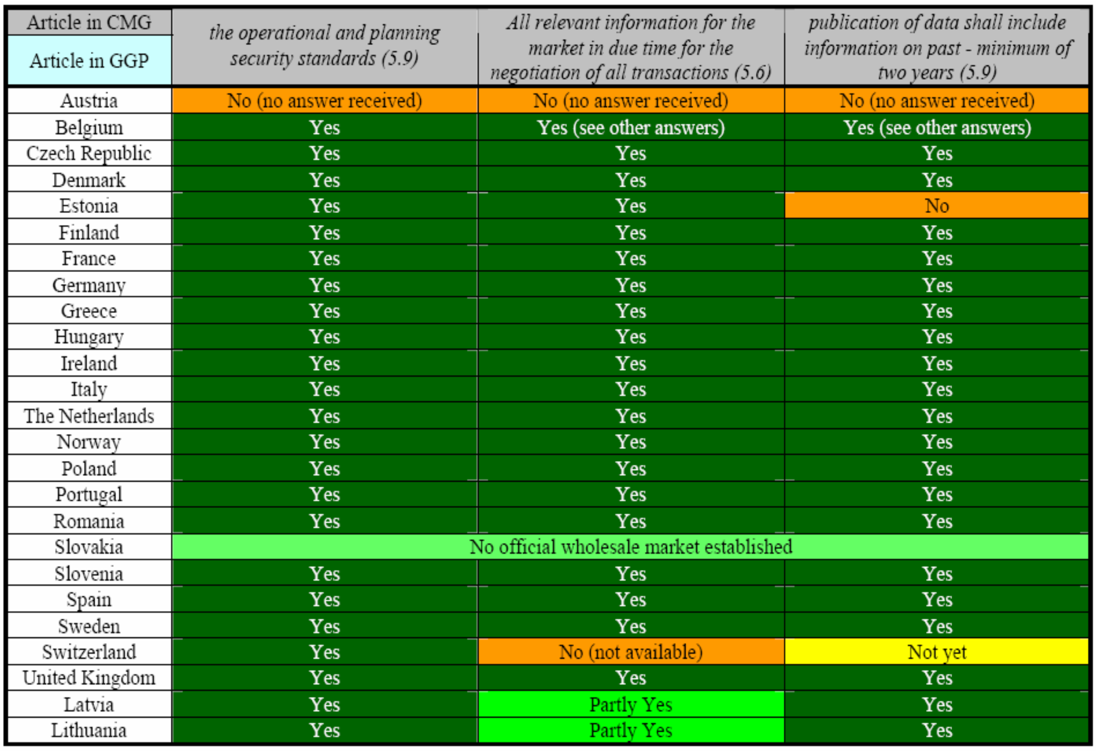
[8] An interesting point of departure for the stochastical description of market prices is the master thesis of G. Vandenbempt (Vandenbempt G., *Analyse van biedcurven op elektriciteitsbeurzen,* 2007, K.U.Leuven). Vandenbempt developed a model to stochastically generate average bidding curves, taking into account seasonal and diurnal regularities. He further applied the model to historic market data from APX in order to generate average APX supply and demand curves.

Table 2: Availability of market data



Article in CMG Article in GGP	*relevant information on the BM (5.7)*	*Volumes of bids and offers used (4.1)*	*Average and marginal prices (4.2)*	*Imbalance prices (4.3)*	*Control area imbalance (4.4)*	*financial balance of the whole market (4.5)*	*Market information on the type of balancing (4.6)*
Austria	No (balancing market is outsourced)						
Belgium	Yes	Yes	Yes	Yes	Yes	No	No
Czech Republic	Yes	Yes	Yes	Yes	Yes	Yes	No
Denmark	Yes	Partly Yes	Partly Yes	Yes	Partly Yes	Partly Yes	No (no relevant)
Estonia	No (no BM)	No (no BM)	No (no BM)	Yes	Partly Yes	No	No
Finland	Yes	Partly Yes	Partly Yes	Yes	Partly Yes	Partly Yes	No (no relevant)
France	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Germany	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Greece	No (no BM)	No (confidential)		Yes	No	Yes	Yes
Hungary	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Ireland	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Italy	Yes	Yes	Yes	Yes	No	Yes	No
The Netherlands	Yes	Yes	Yes	Yes	Yes	No	No
Norway	Yes	Partly Yes	Partly Yes	Yes	Partly Yes	Partly Yes	No (no relevant)
Poland	Yes	No	Partly Yes	Yes	No	Partly Yes	Partly Yes
Portugal	No (no BM)	No (no BM)	No (no BM)	No (no BM)	No (no BM)	No (no BM)	No (no BM)
Romania	Partly Yes	Yes	Yes	Yes	Yes	Yes	Yes
Slovakia	Yes	No (no BM)	No (no BM)	Yes	Yes	Yes	No (no BM)
Slovenia	No (no BM)	No (no BM)	No (no BM)	No (no BM)	No (no BM)	No (no BM)	No (no BM)
Spain	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Sweden	Yes	Partly Yes	Partly Yes	Yes	Partly Yes	Partly Yes	No (no relevant)
Switzerland	No (no BM)	No (no BM)	No (no BM)	No (no BM)	No (no BM)	No (no BM)	No (no BM)
United Kingdom	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Latvia	No	No	No	Yes	No	No	No
Lithuania	No	No	No	Yes	No	No	No

Table 3: Availability of market data



Article in CMG Article in GGP	*the operational and planning security standards (5.9)*	*All relevant information for the market in due time for the negotiation of all transactions (5.6)*	*publication of data shall include information on past - minimum of two years (5.9)*
Austria	No (no answer received)	No (no answer received)	No (no answer received)
Belgium	Yes	Yes (see other answers)	Yes (see other answers)
Czech Republic	Yes	Yes	Yes
Denmark	Yes	Yes	Yes
Estonia	Yes	Yes	No
Finland	Yes	Yes	Yes
France	Yes	Yes	Yes
Germany	Yes	Yes	Yes
Greece	Yes	Yes	Yes
Hungary	Yes	Yes	Yes
Ireland	Yes	Yes	Yes
Italy	Yes	Yes	Yes
The Netherlands	Yes	Yes	Yes
Norway	Yes	Yes	Yes
Poland	Yes	Yes	Yes
Portugal	Yes	Yes	Yes
Romania	Yes	Yes	Yes
Slovakia	No official wholesale market established		
Slovenia	Yes	Yes	Yes
Spain	Yes	Yes	Yes
Sweden	Yes	Yes	Yes
Switzerland	Yes	No (not available)	Not yet
United Kingdom	Yes	Yes	Yes
Latvia	Yes	Partly Yes	Yes
Lithuania	Yes	Partly Yes	Yes

- The Netherlands: APX (www.apxgroup.com)

The APX group - including APX NL and APX UK - only publishes an example file of historical market data (historical market clearing volume and market clearing price) on its website. However, after completing the Data request Application Form and Questionnaire and signing a contract, other relevant historical data can be accessed.

- Others

The Italian power exchange GME (www.mercatoelettrico.org) publishes historical prices (National Single Prices, being the average of Zonal Prices, as well as Zonal Prices) from 2004 up to now. German EEX (www.eex.com) members can trade in German/Austrian ass well as Swiss power on a day-head basis. The Phelix and Swissix, being the average of the hourly auction prices for German/Austrian and Swiss power respectively, are publicly available for 2006 and 2007. More detailed historical data (market clearing volume and market clearing price can only be downloaded after an official request. The Scandinavian Nordpool spot market (Elspot) (http://www.nordpoolspot.com) provides historical day-ahead prices per zone, only for the last 4 weeks. A more extensive database can be accessed on www.nordpool.com after subscription and payment of an annual fee. At the French Powernext (www.powernext.fr), the historical market database can only be accessed after registration. Finally, the Austrian exchange EXAA (http://www.exaa.at) publicly provides extensive historical data from 2002 onwards and is consequently the most transparent of all exchanges mentioned so far.

2.3.2.2 Balancing prices

- Belgium: Elia (www.Elia.be)

On the website of Elia, historical average and marginal prices for upward and downward regulation (secondary & tertiary reserves) are available for 2006 and 2007. Note that, since the Belgian balancing mechanism functions as a pay-as-bid auction, there is no market clearing price. Furthermore, Elia provides historical imbalance prices from 2002 onwards. Note that, up to 2005, the APX and Powernext imbalance prices can be found as well in the excel files. The Belgian imbalance price is based on the prices that Elia charges for balance settlement in the Belgian regulated zone (weighted average downward and upward regulation price). If a Balancing Responsible Party's (BRP) imbalance however reduces Elia's control energy requirements, the imbalance price is calculated according to the reference day-ahead market price. Until 31/12/2006, this reference market price was based on the APX price, but since 1/01/07 the Belpex price is the reference.

- The Netherlands: Tennet (www.tennet.nl)

On the website of the Dutch TSO Tennet, historical volumes of settled regulating power and reserves as well as upward and downward dispatching imbalance prices are available. Note that, since the Dutch balancing market applies uniform pricing, there is a single market price.

- Others

The French TSO RTE (www.rte-france.com) publishes historical data regarding maximum and average upward regulation prices and minimum and average downward regulation prices. Balance settlement price are publicly available as well. The Italian power exchange GME (www.mercatoelettrico.org) also organizes an ancillary services market, of which historical minimum and average purchasing prices and maximum and average selling prices are provided on their website. Note that both balancing mechanisms function, just like in Belgium, as a pay-as-bid auction.

2.3.2.3 Over the counter (long term contract) prices

Data with respect to bilateral trading are generally difficult to find. Neither on the website of Belpex or APX, bilateral trading prices are published. A quick glance at some other European power exchanges shows that the Scandinavian Nordpool (www.nordpool.com) publishes data of OTC futures and forwards contracts for the current day and the previous five days. On the website of the Italian GME (www.mercatoelettrico.org) the introduction of a Forward Electricity Account Trading Platform - in replacement of the existing bilateral platform – has been announced but (historical) data are not yet publicly available.

2.3.2.4 Intra-day market prices

When looking for historical data on intraday markets, it should be noted that not all European countries have implemented an intraday market so far. A quick glance at some European power exchanges shows that the German EEX (www.eex.com) publishes historical intraday prices for 2006 and 2007 and the Italian GME (www.mercatoelettrico.org) from 2004 onwards. On the website of the Scandinavian Elbas market[9] (http://www.elbas.net), historical market data for the four last weeks are available. A more extensive database can be accessed on www.nordpool.com after subscription and payment of an annual fee.

In Belgium, an intra-day market has been introduced on the Belpex platform on 13 march 2008, meaning that the availability of historical market data is limited in time. However, this data is available on the website of Belpex when having a registrated member account.

2.3.3 Stochastic description of market prices

A stochastic model to describe market prices is available at 3E from previous activities. It is based on the same methodology used for the description of wind power output (section 2.2). With this model, time-series of market prices can be generated for the different markets for which data is available. This includes day-ahead markets, intra-day markets and imbalance prices. However, OTC-prices are today impossible to generate due to the lack of available data. These time-series will be generated upon request for the following tasks in the WindBalance project.

2.4 Simulation tool for wind power markets

2.4.1 Introduction

With the program for time series generation of wind power and market prices, 3E developed a simulation tool. This tool can perform long term predictions of the market value of wind power, and can be used to evaluate investments. Since the simulation tool allows easy adjustment of input time series and input parameters, it can also be used to assess the value of wind energy on different

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[9] The Elbas market is a market that enables real time trading around the clock every day of the year, covering individual hours up to one hour before delivery. Its function is to be the aftermarket to the Elspot market at the Nordic power exchange Nord Pool.

markets. Depending on the input, different kinds of evaluations are possible, e.g. the value assessment of short-term wind power predictions (day-ahead or rolling intra-day).

The overall objective of this task is to estimate the value of wind energy on the electricity markets and the added value of different kinds of wind power predictions. After the methodology is explained in the first section, the second section evaluates the value on the power markets of wind energy in different configurations. The third section evaluates the value of different kinds of wind power predictions and the possible improvements when taken into account the resulting balancing costs.

2.4.2 Methodology

2.4.2.1 Fixed price OTC equivalent

Since wind energy is variable, it is difficult to make an accurate estimation of its market value. The developed program allows such value assessment following a statistical approach.

For reasons of simplicity and risk reduction, a fixed price is often settled in an OTC contract between the wind farm operator and an electricity supplier. With this price agreed, the evaluation of the investment in the new wind farm becomes fairly easy at an early stage, allowing quick value assessment of a new wind farm.

The developed tool calculates the value of wind energy when traded on the power exchange. By combining time series of energy production and market prices taking into account inflation, and dividing the resulting income generated on the power exchange by the amount of energy produced, this value can be expressed in terms of a price per unit of energy. Since this fixed price is equal to the average value of the electricity produced by the wind farm taken into account the imbalance costs, it can be compared to the fixed price agreed in OTC contracts. Therefore, we call this the 'fixed price OTC equivalent' of the wind energy produced, when traded on the power exchange.

The calculation of this fixed price OTC equivalent makes the tool a valuable support for both parties in the negotiations of OTC contracts. Moreover, the tool provides a base for an objective analysis of the real market value of wind energy.

2.4.2.2 Value assessment methodology

The developed simulation tool combines the generated time series for wind power and wind prediction with generated series of market and imbalance prices. The value assessment of wind energy on the power exchange is done by calculating the fixed price OTC equivalent (see previous section). For the generation of price series, historical day-ahead and imbalance prices are used. Since the intra-day market in Belgium is very new, not sufficient historical data is available for the generation of useful time series. To assess the value of intra-day forecasts for wind energy, the simple assumption has been made that intra-day market prices are similar to the day-ahead prices.

For the generation of wind power output and wind power predictions, historical data is used from Belgian wind farms and from the four German control zones. It is important to mention that the available historical prediction time series of the Belgian wind farms did not yet include feedback of the results to the prediction model. Such feedback makes the model more accurate, and is done in most of today's state-of-the-art predictions. The value of Belgian wind energy and wind power forecasts today will thus be somewhat higher than the figures mentioned in this report.[10]

To calculate the real market value of wind energy and wind power forecasts, the generated series are combined according to the following formula:

Value = (pred * price + pos_error * posimbprice – neg_error * negimbprice) / total_prod

With:

- Value = Fixed price that should be paid on the OTC market to equal the revenues that can be reached on the power exchange
- Pred = Wind power prediction as nominated the day before delivery
- Price = Day-ahead market price settled the day before delivery
- Pos_error = Equals the prediction error when real production is larger than the power predicted
- Posimbprice = The positive imbalance price = price that will be paid for the extra energy generated when the real production is larger than the nomination
- Neg_error = Equals the prediction error when real production is smaller than the power predicted
- Negimbprice = The negative imbalance price = price that has to be paid to buy the difference in energy when the real production is smaller than the nomination
- Total_prod = Total energy produced in the observed period

2.4.2.3 Imbalance loss

When real wind power production is different from the day-ahead nominations, an imbalance is created by the wind farm. In case this imbalance is not eliminated by imbalances from other power generation facilities in the portfolio, imbalance costs will have to be paid which can be significant.

When real production is larger than the nomination, the difference can be sold at a lower price than the market price. This price is called the positive imbalance price, and lies in the range of 0-92% of the market price. When real production is smaller than the nomination, the difference must be bought at a higher price which is called the negative imbalance price and is at least 108% of the market price.

These imbalance costs lead to a loss of income for the wind farm and thus reduce its value. In the next sections, the relative loss of income (imbalance costs / market value with day-ahead predictions) due to the imbalance costs is called 'the imbalance loss'.

The imbalance loss due to imperfect predictions is an important figure. It clearly shows the economic improvement that is possible with better forecasts or with other measures to reduce imbalance. Figure 7 shows a graphical example of the imbalance loss over time due to imperfect wind power predictions.

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[10] The RMSE of the used historical data is about 15% for predictions for a single wind farm. With today's state-of the art forecasts with feedback of results to the prediction model, a Root Mean Square Error of about 10% can be obtained. At the time of project execution, sufficient historical data with such forecasts was not yet available.

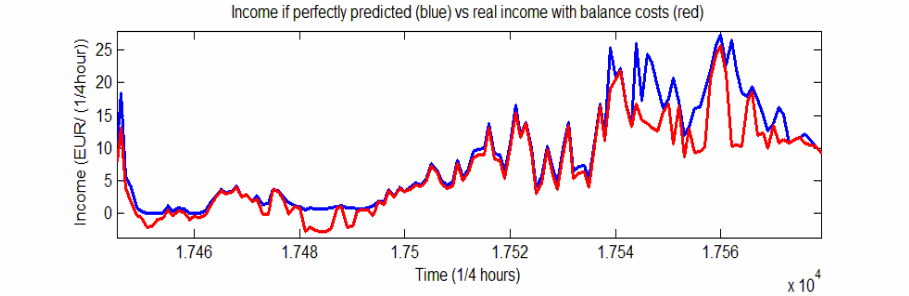

Figure 7: Income if perfectly predicted (blue) versus real income with balance costs (red) (data 3E)

2.4.3 Market value wind energy

2.4.3.1 Fixed price OTC equivalent for different wind power configurations

In this section, the value of wind energy is calculated for different wind power configurations (single turbine, wind farm or wind farm region). These configurations have a different value because of economies of scale: the larger the involved area, the more accurate the aggregated wind power predictions. It is important to note that for reasons of simplicity and budget constraints, effects of wind energy on the market prices have not been modeled. This assumption is a good approximation when the contribution of wind power compared to the total energy production is limited. However, for regions with significant relative contribution of wind energy[11], this effect should be integrated in the model to produce more accurate results.

The calculation of the fixed price OTC equivalent takes into account an electricity price 'inflation' of 6% (based on the evolution of the industrial electricity prices in Belgium between 2002-2007 (Eurostat). In this section, it is calculated for the year 2009.

2.4.3.2 Single wind turbine

With a generated average Belpex day-ahead price of about 75.3 €/MWh for 2009, the fixed price OTC equivalent for a single wind turbine in 2009 is estimated at around 66.3 €/MWh. The root mean square error (RMSE) of the predictions is around 16 %, and leads to an income loss of about 18 % due to the imbalance costs.

2.4.3.3 Wind farm

For a small wind farm of 4 turbines, the fixed price OTC equivalent estimated is equal to 67.2 €/MWh. The RMSE is about 15.7 % and the income loss is estimated to be 14.3 %. A larger wind farm of 8 turbines generates electricity at an estimated fixed price OTC equivalent of 67.8 €/MWh. The RMSE of the predictions is 15.5 % and the income loss is about 13.9 %.

2.4.3.4 Larger wind region

The combination of 3 Belgian wind farms allows estimating the fixed price OTC equivalent when forecasting for a whole region. Due to the larger geographical spread, the variability is reduced significantly: the RMSE is about 11 % and the income loss is reduced to about 10.6 %.

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[11] A good example of this is Germany with its significant capacity of wind energy [19]. In the future with larger capacities of wind power and with larger transmission capacities, this effect will become important also in the future pentalateral market (integrating Belgium, Netherlands, France, Luxemburg, Germany).

To analyze a larger geographical spread, wind production and prediction data of the four German control zones is used. The normalized wind power (for 1 MW) in the EON control zone combined with the Belgian spot market prices and imbalance prices allows quantifying the effects of reduced variability. For this control zone with the Belgian prices, wind energy would have a fixed price OTC equivalent of 74.7 €/MWh, with a prediction RMSE of 7.8 % and an income loss of 8.2 %.

The combination of all German wind data allows analyzing an even larger spread. The reduced variability can be seen in the reduction of the RMSE to 4.8 % and of the income loss to 5.3 %. The value of combining predictions for wind farms with such a large geographical spread[12] would be about 76.7 €/MWh.

The aggregation of wind power over large regions also has other advantages. The variability of the wind power output can be significantly reduced, as shown in the 3E report 'A North Sea Electricity Grid [R]evolution', commissioned by Greenpeace. This has a very positive effect on the planning and operation of the power system and reduces the requirements for flexibility. To take advantage of this aggregation effect, sufficient interconnection capacity is crucial. [35]

2.4.3.5 Conclusion

Aggregating predictions for several wind farms reduces variability and thus the relative total prediction error and the resulting total imbalance. These economies of scale can clearly be witnessed when comparing the above results. The value of wind energy when the predictions are combined in one nomination for a large region can be up to more than 20 % higher than when the nomination is done per wind turbine.

2.4.3.6 Statistical forecast of fixed price OTC-equivalent for the coming 10 years

A tool for the generation of synthetic market results was available at 3E. By applying outputs from this tool, a statistical forecast of the value of wind energy can be made for the coming years. Based on the input series of Belpex spot market prices of 2007 until mid-2008 and input series of wind energy production and prediction of a Belgian wind farm of 8 MW, the developed tool generates new series of wind power, wind power prediction, spot market prices and imbalance prices which are used for a statistical value assessment.

For an 8 MW wind farm to start producing beginning 2009, the fixed price OTC equivalent for the next 10 years is estimated to be 90.6 €/MWh. This means that the wind farm operator could negotiate with the supplier for a fixed price of up to 90.6 €/MWh for all electricity produced by the new wind farm in the next 10 years. When the 8 MW wind farm has about 1760 full load hours, this fixed price contract would generate a yearly income of 1 275 648 €.

2.4.4 Market value wind power predictions

Without the use of advanced weather predictions and wind power forecasting tools, the value of wind energy on the market would be significantly lower than described in the previous section, due to the higher imbalance created in the system and the resulting economic losses.

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[12] As already mentioned above, this analysis doesn't take into account the effect of wind energy on the market prices.

A simulation of different kinds of nomination strategies can be used to assess the real value of wind power forecasts. Moreover, it allows estimating the extra economic margin attainable by improvements in wind power forecasts. The following analysis is done for a Belgian 8 MW wind farm for 2009.

2.4.4.1 Value wind energy with perfect predictions or perfect intra-day market trade[13]

Firstly, for reasons of comparison, it is important to look at the direct market value of the produced electricity with perfect predictions. This represents the optimal value: its momentarily value on the power exchanges would be maximized. Alas, perfect predictions are not possible. In reality there will always be a prediction error which eventually can lead to imbalances. However, the value of wind power with perfect predictions is a good reference for comparisons. At the same time, it clearly shows the possibilities for improvements.

For a Belgian 8 MW wind farm, the fixed price OTC equivalent for wind energy with perfect predictions is estimated at 78.3 €/MWh for the year 2009.

2.4.4.2 Value of wind energy without forecast

When nominating without predicting, the value of the sold wind energy is significantly lower. For a nomination which is always equal to zero, the fixed price OTC equivalent for 2009 for the same Belgian 8 MW wind farm is estimated at 42.5 €/MWh. This is roughly about 60% of the market value with day-ahead state-of-the-art predictions. The RMSE of this nomination is equal to 30.9 %, while the resulting imbalance loss is approximately 46 %.

For a nomination which is always equal to the average wind energy production, the fixed price OTC equivalent is about 57.5 €/MWh, with a RMSE of 24.0 % and an associated imbalance loss of approximately 26.5 %.

2.4.4.3 Value of wind energy with forecast based on persistence

The value of wind energy with predictions based on persistence on the average production of the day before nomination, is estimated at 56.5 €/MWh fixed price OTC equivalent. The RMSE is approximately 26.9 % and the imbalance loss compared to the value with perfect predictions is about 28 % of the market value with this forecast. Apparently, the value of wind energy with this forecast is lower than when always nominating the average production.

With persistence based on the value of two hours before nomination (D-1 h9), the fixed price OTC equivalent is estimated at 54.5 €/MWh with an RMSE of 31.1 % and a corresponding imbalance loss of about 30%.

2.4.4.4 Value of wind energy with state-of-the-art day-ahead forecasts

Results for state-of-the-art forecasts have already been given in above. For easy comparison, the data for an 8MW wind farm are recalled here: The fixed price OTC equivalent of wind energy with

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[13] As mentioned above, the assumption is made that prices on the intra-day market are similar to those on the day-ahead market, due to a lack of historical data.

state-of-the-art day-ahead forecasts is approximately equal to 68.6 €/MWh, while the RMSE of the predictions is 15.5 % and the imbalance loss is approximately equal to 14 %.

2.4.4.5 *Value of wind energy with intra-day forecasts*

Recently, the Belgian power exchange Belpex installed an intra-day market for electricity. This market can be used to reduce existing imbalances between day-ahead nomination and real-time production by means of trade. With such a market in place, it is generally interesting to continually update the nominations made day-ahead with intra-day wind predictions, this way improving the value of wind power. As mentioned above, due to lack of data the assumption is made that the intra-day prices are equal to the day-ahead market prices.

Intra-day predictions are introduced in the program by reducing the standard deviation of the prediction error. The calibration of this reduction is based on figures from Tradewind[18].

For an 8 MW wind farm on an intra-day market with gate closure time of 4 hours (4-hour rolling intra-day market), the fixed price OTC equivalent is about 72.1 €/MWh. The shorter prediction horizon reduces the RSME of the prediction to 9.2 %, which reduces the corresponding imbalance loss to 8.6%. If gate closure time is reduced further to 2 hours (2-hour rolling intra-day market), the fixed price OTC equivalent is about 72.4 €/MWh. The shorter prediction horizon reduces the RSME of the prediction to 8.5 %, which reduces the corresponding imbalance loss to 7.3%.

3. Top Down Research (phase 2)

3.1 Belgian electricity generation system with wind power

In Task 5, the Belgian electricity generation system is modeled and examined in terms of technical boundaries. This is further elaborated in the following. The cost and greenhouse gas impact of wind power is covered in the report of Task 5 [21].

3.1.1 Data used

In a regular operation of the mentioned electricity generation systems, nuclear power plants operate in baseload. With the chosen fuel prices, based on the International Energy Agency (IEA) World Outlook prices of 2005 [22], coal power plants come second after these nuclear plants in terms of fuel costs[14]. Gas-fired power plants, especially the efficient CC power plants, are also used extensively due to their flexible operating characteristics. These can easily adjust to changes in supply and demand. Smaller plants such as gas turbines and diesel motors are used for temporal needs, mostly to cover short-term peaks in demand. They offer more flexibility to the system.

Apart from varying systems, other variables are examined as well to observe their combined effects on wind power integration. Four different wind speed profiles are chosen to represent typical patterns in wind power output during a day. They are based upon actual data from the Belgian Meteorological Institute which are measured at a 10 m altitude and extrapolated to 80 m data applying the power law [23][24]. The transformation from wind speed to wind power is based on the Vestas V80 wind turbine power curve [25]. Wind power is typically a variable energy source, which becomes clear when looking at wind power profiles. The profiles that are applied in the MILP model, depicted in Figure 8 and also used in [26], represent the fluctuating behaviour of wind during a day. As the aim is to investigate the wind speed levels as well as the fluctuations in wind speed, no geographical smoothing of the profiles takes place. In the simulations, the fluctuations have to be dealt with using different systems.

The other important characteristic of wind, namely the unpredictability and the related need for accurate forecasts is not dealt with in this paper, meaning that the security of the system is implicitly assumed to be maintained. Other studies have demonstrated the importance of the accurate forecast of wind power [27][28]. However, in what follows, solely the variability is focussed on. Increasing amounts of wind power are considered as well to investigate the effect of total wind power capacity on the system. The amount of installed capacity of wind power in the three abovementioned systems varies from 0 to 2000 MW.

Apart from applying different wind profiles, different demand profiles are being looked at too. These are shown in Figure 9 and are taken from actual 2006 demand data from Elia, the Belgian transmission system operator (TSO) [29]. They are chosen as to represent distinct demand situations and have also been used in other studies .

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[14] The used IEA prices mention a crude oil price around 36 $/barrel, where it has risen to above 100 $/barrel in 2008. However, the actual prices are of less importance than the ratio between them. The focus is not so much on the overall fuel cost than on the effects of the use of different fuels.

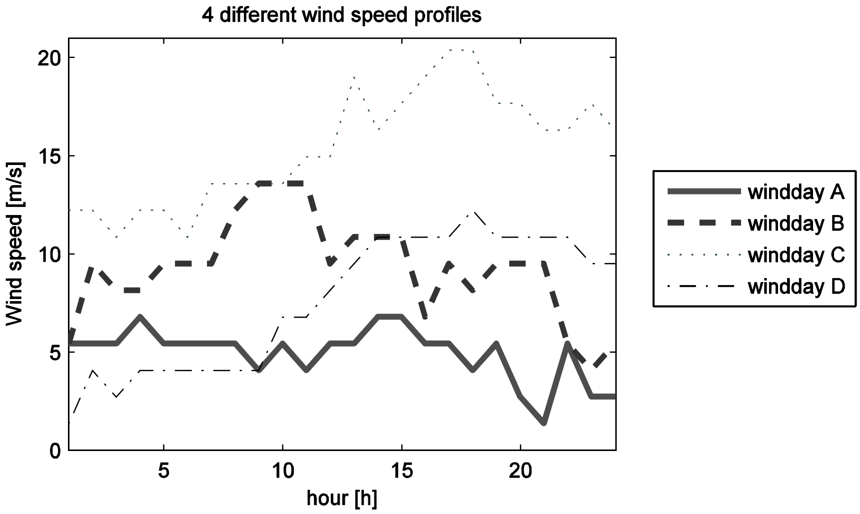

Figure 8: Wind speed profiles of 4 different days, showing typical fluctuations .

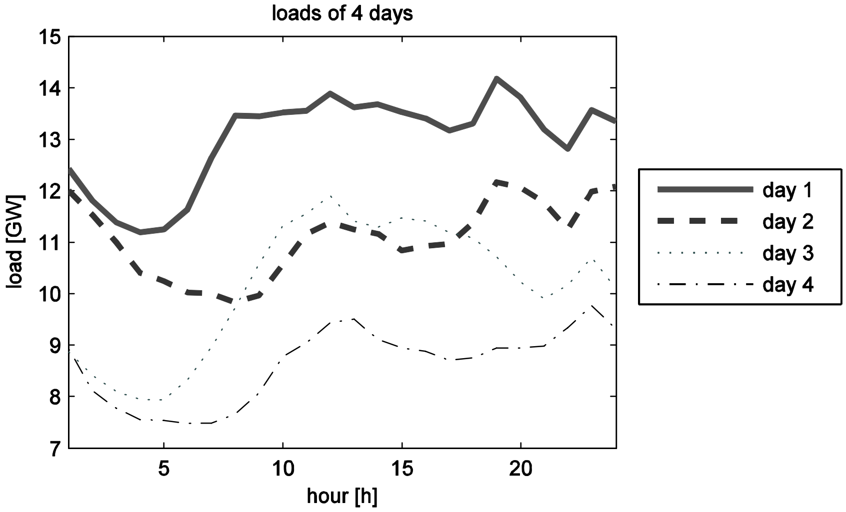

Figure 9: Demand profiles of 4 different days based on actual 2006 demand data of Elia .

The MILP model that simulates the different cases runs on a 24h basis[15]. It calculates a cost-optimal operation of the system under the defined constraints. It takes system-specific elements such as operation points, part-load efficiencies, ramping rates, minimum up and down times, contribution to spinning reserves and fuel usage into account. Apart from meeting the demand, the system is

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[15] For more information regarding the MILP model, [5][30][31] are referred to. For computational reasons the time frame is restricted to 24h. Since the aim is to compare different situations for wind power introduction rather than simulating what would happen over a longer period of time, this approach gives the necessary insight.

operated in a way that a certain amount of spinning reserves, which should amount to 1050 MW, is met.

3.1.2 Constraints on wind power in Belgium

3.1.2.1 Perfect forecast of wind power

When the actual wind power output is perfectly known during the UC period, the operation of the system experiences practically no hinder from the wind power integration. The power plants can be switched on and off according to the most optimal schedule so that supply and demand are balanced at all times. Only in the case of a seriously underdimensioned electricity generation system will the operation of the system experience problems in the hour-by-hour operation of the system. As expected, no actual technical limits were incurred in the performed simulations.

3.1.2.2 Forecast error applied to wind power

In a second analysis, the system operation is studied with the possibility of a forecast error on the wind speed prediction and ensuing wind power output. In the Unit Commitment (UC) phase, a certain amount of electricity from wind power is foreseen, based on the forecasted wind speed. Afterwards, in the dispatch phase, the actual wind speed can diverge from the forecast, leading to necessary adaptations in the system on the short term. Depending on the activated power plants, the system will adapt to the actual wind power situation.

The ramp rates, minimal operation points, partial load efficiencies and minimal up and down times of the power plants constitute the most important characteristics in the capacity of the system to integrate the wind power output with its forecast errors into the operation of the system. Two technical barriers to the integration of this wind power can be distinguished. Firstly, the power plants that were activated during the UC phase and that are available through fast start up may prove to insufficiently cover the gap between forecasted and actual wind speed value. For large absolute amounts of positive forecast error, the current operation of the Belgian system might prove to be insufficient. Secondly, a negative forecast error, where a significant amount of wind power is unexpectedly delivered, can cause a situation of overproduction. In some cases, the system cannot adapt fast enough to this situation and electricity from wind power needs to be curtailed. In the following, both the situations with and without curtailment of wind power are investigated.

Without curtailment of wind power

In a situation where no curtailment of wind power is possible, the two abovementioned technical barriers can arise. Since both large amounts of wind power and large absolute forecast errors are considered, many demand-supply imbalances occur that cannot be met by the available capacity in the system.

In a first instance, the situation with a positive forecast error is investigated. This refers to a situation leading to lower actual winds speeds than forecasted. When a consistent positive 2 m/s wind speed forecasting error is set, problems during dispatch already occur with the high load profile of Day 1. Several elements come into play when forecast errors are made.

Firstly, the overestimation of wind energy needs to be balanced by the active power plants in the system. An amount of "spinning reserves" is required at all times, which is concretized by a minimum amount of available capacity in the system for every hour. These reserves can be used to meet discrepancies between demand and supply. Sometimes however, more reserve capacity than minimally set is available, mostly in situations with low demand and corresponding many power plants operating at partial load, offering more options in terms of reserve provision. That is the main reason why the fewest technical barriers are met in Day 4.

A second logical element is the absolute level of the forecast error. With large forecast errors, more effort is needed for balancing the system again. Problems with forecast errors occur most frequently for the combination of relatively high levels of installed wind power capacity with the occurrence of high wind speed profiles. In this case winddays B and D lead to the largest technical barriers. The same exercise for a positive 1 m/s forecast error learns that the limits of wind power integration in the system are situated at a higher level, in these particular cases resulting in no technical barrier to be found for a 1 m/s positive error.

An exception for the above is true for Windday C. The reason is to be found in the shape of the power curve of the wind turbine, which defines how much wind speed corresponds to a certain amount of wind power. Not only the absolute level of wind speed plays a role in the impact of a forecast error, the actual shape of the power curve is an important element to consider as well. Since, according to the Betz model the transformation function of wind speed to energy is a cubic equation, the impact of an erroneous forecast is highest in the middle regions of the power curve, typically for wind speeds between 5 and 12 m/s. That is the reason why Windday C, which has wind speed values around the rated wind speed of the turbine, experiences less difficulties in coping with the forecast error, seeing as the same absolute wind speed forecast error results in a smaller forecast errors expressed in terms of wind power output, when compared to, for example Windday B and D. The latter are situated in the steepest part of the power curve and experience the largest impact in terms of absolute wind power changes for the same amount of wind speed error.

Also very important is the sign of the forecast error. So far, only the positive forecast errors were discussed. Since no curtailment of wind power is foreseen, some situations might see the system not being able to cope with certain amounts of wind energy that need to be absorbed. This then results in difficulties to balance demand and supply.

The ability of electricity generation systems to absorb the overproduction in wind energy depends to a large extent on how much the active power plants can still lower their output regime. Power plants operating at full load might have to switch to partial load. Problems however occur at times of low demand during the day when a great share of power plants are already operating at partial load. The system then cannot always lower its electricity output in such extent that the extra wind energy can be taken in.

The reason for Windday D facing most difficulties is to be found in the wind speed already being very high so that the unexpected 2 m/s increase does put more stress on the system, which has to absorb all the extra energy. This is more difficult for a system which already has to significantly adapt its output to the massive amounts of wind power.

The real problems start for lower demand profiles. These coincide with many power plants already operating at partial load. Therefore, with large amounts of unexpected wind energy to be absorbed by the system, more difficulties arise in those events where the load level of the active power plants cannot be lowered much more.

With curtailment of wind power

When excess wind power output can be curtailed, fewer problems arise in terms of power plants being able to absorb the additional energy. Whenever a negative forecast error is made, the additional wind energy can always be curtailed if the system is not able to cope with a sudden change. This severely reduces the technical barriers the model is faced with when a negative forecast error is made. For positive forecast errors, the technical barriers persist since curtailment offers no additional relief. For negative forecast errors, the curtailment offers solutions where the system previously could not cope with the uncertainty.

The amount of wind energy that needs to be curtailed varies according to the chosen variables. Logically, more wind energy output increases the probability of curtailment becoming necessary. More wind that needs to be absorbed by the system leads to more potential problems. Another, even more important, parameter is the demand profile. Lower profiles have more difficulties integrating all of the produced wind energy. It is not surprising the largest curtailments indeed occur for combinations of low overall demand with high levels of generated wind energy on the same moments as the demand lows. The combination of the four demand and wind speed profiles is represented in Table 4.

Table 4: Amount of wind energy curtailed in 24h for every combination of demand and wind speed profile, in MWh. A negative forecast error of 2 m/s is used on an installed capacity of 3000 MW wind power.

	Windday A	**Windday B**	**Windday C**	**Windday D**
Day 1	0	0	0	0
Day 2	0	32	1183	0
Day 3	0	3736	4392	0
Day 4	335	7796	2799	7020

3.1.3 Belgium in a more European context

Several aspects of wind power can be seen in a more European context. Only looking at Belgium, disregards important opportunities for easier wind power integration. Three of these are briefly discussed, namely the need for spinning reserves, the availability of pumped hydro and the geographic spreading of wind power.

Spinning reserves are needed to deal with unexpected situations. Looking at one country as an isolated case, a considerable amount of spinning reserves is needed. If one power plant or other element in the system fails, this has to be covered within the system itself. However, when combining two or more systems with eachother, the required spinning reserves for the same level of reliability will not be the sum of the separate spinning reserves. This is because the unexpected events of two different systems, which can be represented by a standard deviation on the expected situation of a system, are usually not fully correlated. Following formula of the sum of two standard deviations shows how the deviation of the sum will always be smaller than the sum of the deviations.

When combining the operation of two systems, through interconnections, the overall need for spinning reserves decreases together with the standard deviation. It allows the systems to operate under the same reliability levels, while at the same time reducing the costs spent on spinning reserves. On the other hand, it can also be wise to keep the same levels of spinning reserves, which eventually results in improved reliability of the system. Especially with large amounts of wind power, it is important to most optimally apply reserves to cope with the increase in uncertainty.

A related opportunity of the linkage between countries is the fact that the cheapest options for generation and for spinning reserves will be used, disregarding the system of origin. The overall generation costs therefore also decrease. Pumped hydro storage is often used for coping with both the uncertainty and variability in the system, such as the ones caused by wind power. With a European linkage, disregarding grid limitations, Belgium can also access hydro storage in the Alps or hydro power in Norway for example. These additional opportunities drive the costs for coping with the intermittency of wind power downwards. A more detailed analysis of how the cheapest production units are used in a European context however, falls outside the scope of this analysis but has already been covered in literature, such as in [32][33].

Finally, considering wind power in a European context allows for geographic spreading of wind power generation. The further apart wind farms are placed, the less correlation there will be between them, leading to less variability in the entire system. An analysis of the difference in hourly power output has been performed for Belgian and Dutch meteorological data and this for the years 2001 to 2006 [22][34]. The frequency of occurrence of changes of a certain amount of MW for a one-hour interval is compared for three different situations. The analysis is performed for a nominal power of 1 MW. Changes of up to 1 MW do occur, meaning that the wind power output can shift from 0% to 100% of nominal power and vice versa. When considering three sites in Belgium, still taking a 1 MW total nominal power, the spread of the hourly changes becomes more narrow and no event of a 100% change in power output over one hour can be noted. Taking the geographical spread even further, the case for a Belgian-Dutch situation is examined. The changes over one hour over this entire zone, being composed of 9 wind power producing site, spread over the two countries, are considerably smaller than in the two other cases. The maximal hourly change amounts to 30% of the 1 MW nominal power.

Taking even larger interconnected zones will lead to even less variable wind power production.

3.2 Introducing network constraints

As there is some delay in the Task 6 of the WindBalance project, final results will not be obtained in BEAMS before mid-2009. The assumption that no bottlenecks are present in the European grid is clearly an enormous simplification of reality. Therefore, in this task, this assumption is dropped and grid constraints are added to the exercise. This will reduce the maximum potential for wind capacity. The maximum amount of wind power that can be integrated in the grid will be quantified using a reliability assessment analysis.

3.2.1 The reliability assessment analysis

The overall purpose of the reliability assessment analysis is to assess the impact of wind power production on the security of electricity transport. Therefore we will model the impact of offshore wind power production on the Belgian grid. The core of the risk assessments study is a load flow analysis that establishes all the active and reactive power flows in the network branches, for a given state of consumption and generation. Two options have been analysed to perform the study :

1. Using MatPower, a package of Matlab functions specialy dedicated to run power flow & optimal power flow calculations.
2. Using another software (bought by BEAMS) that will provide other services as unit commitment, contingence analysis, Monte Carlo simulations, etc. As this software will be chosen by end of January 15 (a market study is currently in progress), we call it "Software XYZ" in the following pages.

As time is short to model every module in Matlab, the second solution is likely to be chosen soon.

Monte-Carlo simulation vs. Markov process

A single load flow analysis can deliver helpful information on the congestions that can occur in a network for a given state of load and generation at each node. Likewise, an optimal power flow analysis is useful to determine an optimal production cost with no network constraints, given the load at each node and the generation cost of every power plant. However, these single analyses are hopeless when it comes to assess the network behavior in the long run or to determine the network response to unpredictable events (mostly, the outage of a branch or a generator). Then, the very general goal of the modules we will add to the MatPower package (or the Software XYZ) is to model:

- The network **chronological or Markovian behavior**. It is to say, the variables defining a network state (load, availability of elements, wind production) at a given moment (say, N) will have an influence on the next network states (N+1, N+2, etc.).
- The network **random behavior** (thanks to a Monte-Carlo simulation). This random behavior is present in the Boolean state generation model (it determines the branches and plants forced outages) and in the Load evolution model (random component of the load). Practically, a great amount of states (typically ten thousands) will be analyzed, so that a statistical analysis of the results is made possible.

3.2.2 The Modules

The core of the risk assessment analysis is the "Processing" part, made of hydro and thermal unit commitment as well as load flow calculations. However in order to run effectively, this processing part needs to handle a bunch of input data that are prepared upstream in the "Pre-processing" part. Finally, output data are processed in the "Post-processing" part in order to obtain the needed results. Every part is made of several "modules" that will be described in detail in the following pages. Figure 10 presents the different modules valid in both cases: modules added to the MatPower load-flow package & modules added to another risk assessment software.

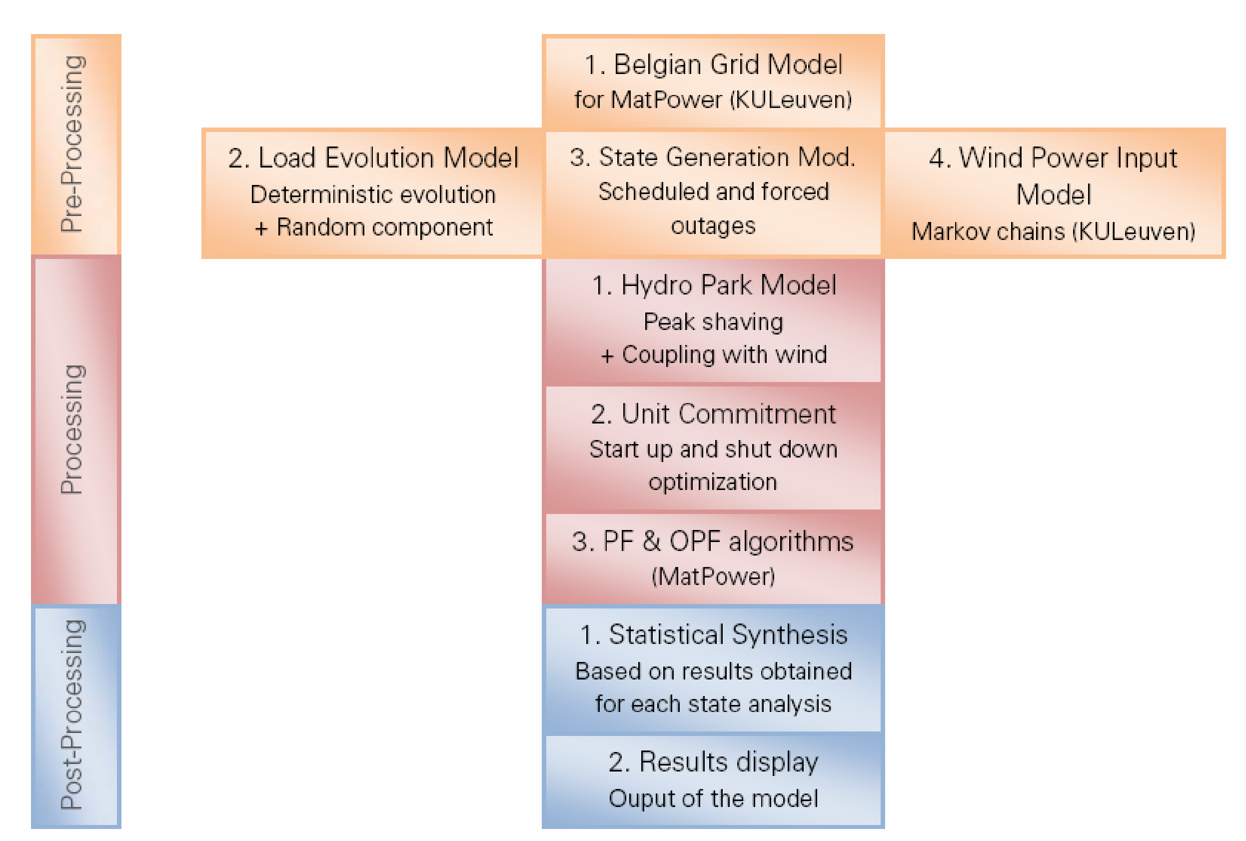

Figure 10: Schematic overview of model implementation

3.2.2.1 Pre-processing

Basically, the "pre-processing" modules are upstream of the scheduling and load-flow algorithms; their outputs are the inputs of the "processing" modules. They put in place the network that will be analyzed (Belgian Network Model), the load evolution among buses (Load Evolution Model), the various network incidents that may occur (Boolean State Generation Model) and the wind power production whose impact will be quantified later (Wind Power Input Model).

The Belgian network model description has been delivered by ESAT-Electa (KULeuven). The network described here-under is the version received from KUL in august 2008. It is several years old and an update is nowadays being made by two researchers from KULeuven – new buses, branches and generators are still being added to the model. The network description received is to be run with MatPower for one single load-flow analysis. Therefore, the topological data (node names, connections…) and elements characteristics (maximal flows, maximal power outputs…) can serve for every load-flow analysis, but some data will vary if various load flow simulations are to be considered. Thus, each network state can be described by:

- **Loads**: active and reactive power demand at each node. The hourly variations at each load will be simulated both deterministically and randomly
- **Power production**: each generator's active and reactive power output will vary on an hourly basis. These variations will depend on the load, the Hydro Park and Unit Commitment models as well as the Optimal Power Flow algorithm
- **Elements availability**. The network must be able to bear the loss of several elements (buses, lines, generators, transformers) without jeopardizing the electricity supply from producers to final consumers. Therefore, safety analysis must consider the effect of every possible

incident and Monte-Carlo simulations are the best way to assess the overall safety of supply. A forced outage rate (FOR) must then be assigned to every elements that can possibly be unavailable.

The network provided ranges from 380kV to 30kV (plus some 15-10kV elements). Almost 86% of the nodes are on the Belgian territory, the others are split between the border countries. The network has 1412 Buses, 2062 lines and busbars, 283 generators and 344 transformers. Loads are specified at each bus (when accurate) for the single network state analyzed in the MatPower case for a total amount of 319845 MW and 17384 MVAR (in Belgium : 15075 MW and 4921 MVAR). Each one of the 1951 lines is referenced with the ID number of the two buses it connects. Resistance, reactance and susceptance are defined for all the real lines, as well as apparent power flow maximum limit (in MVA). Fictive lines linking external and equivalent nodes have an arbitrary limit fixed to 9999 MVA; their resistance and reactance can be negative. In the Belgian Case file received, there is no real limit (minimum and maximum) fixed for the active power. Having accurate values for power output limits is essential when running an Optimal Power Flow Algorithm. Indeed, cheaper generators will tend to produce near to their maximum. Nevertheless, we can assess that all the small generators (Pg<50 MW) with zero cost actually produce at their maximum level in the Belgian case. Thus, their Pmax is equal to their Pg value. These are essentially cogeneration and other renewable energy units, for a total output of 576 MW in Belgium. Pmax values for bigger generators remain to be found; annual reports of Electrabel and SPE should help to find these values.

The cost model given to each power plant will determine its production level in the Unit Commitment and Optimal Power Flow algorithms. Basically, a cheap power plant will produce more and more often than an expensive one. However, more complex considerations are to be considered, e.g. start up and shut down costs. Cost model is a key factor to model correctly the generating facilities: it will determine which plants produce on a permanent planning (base production) and which ones produce when demand is high (peak production).

In the Belgian model, plants have a quadratic cost model. We only have the 2 first coefficients; therefore the cost model is linear. Start up and shut down cost are also defined for unit commitment matters (practically, start up cost is equal to a fixed cost c0). Among the Belgian facilities, there are different cost models:

- Zero cost model: these plants produce every time they are available.
- Little fixed cost, zero linear cost. These units are committed secondly
- Higher fixed cost (ranging from 100 to 300 €/MW) and non-zero linear cost (ranging from 10 €/MW for nuclear plants to 60 €/MW). The linear cost is essentially linked to combustible price.

We must be careful to differentiate linear prices sufficiently, so that the Optimal Power Flow algorithm can run without error. Indeed, this algorithm basically consists of the optimization of a cost function, with equality and inequality constraints (Kuhn & Tucker algorithm). Very similar costs will likely lead to a very "flat" function without an optimum.

Load evolution model

When assessing the security level of a given electrical network in terms of adequacy between production and consumption as well as congestion risks, it is essential to analyze its behavior in a great range of consumption situations, going from annual load trough to annual load peak. However, considering the 8760 annual values of hourly load for each one of the ~700 loads would lead to the handling of more than 6 millions values, which is not feasible (moreover, we don't even know the hourly load evolution at each node). Therefore it is necessary to create a simplified but realistic model. On a national level, load is well known and can be predicted with a good accuracy level. Load varies at different time scales:

- Yearly variation : depending on the seasonal variations of temperature and on national holidays.
- Weekly variations: 5 working days with similar daily load curves; Saturdays and Sundays.
- Daily variations : depending on the economic activity (working hours) and people's habits.

The deterministic part of the hourly load evolution at each node is modeled by its annual load peak, as well as modulation diagrams (weekly, hourly). The Belgian load data used to build these diagrams come from Elia's website. We also have modulation diagrams for France (RTE) and Germany (RWE, EON, Vattenfall, EnBw). Thus, all the French and German loads will evolve differently. As we don't have data from the Dutch TSO Tennet, we make Dutch loads evolve as Belgian loads.

Based on the modulation diagrams, Figure 11 show the hourly load evolution for the first week of 2007 (from January 1 to January 7). We can clearly see that a load exceptional behavior (e.g. January 1, holiday) is not taken into account by our model.

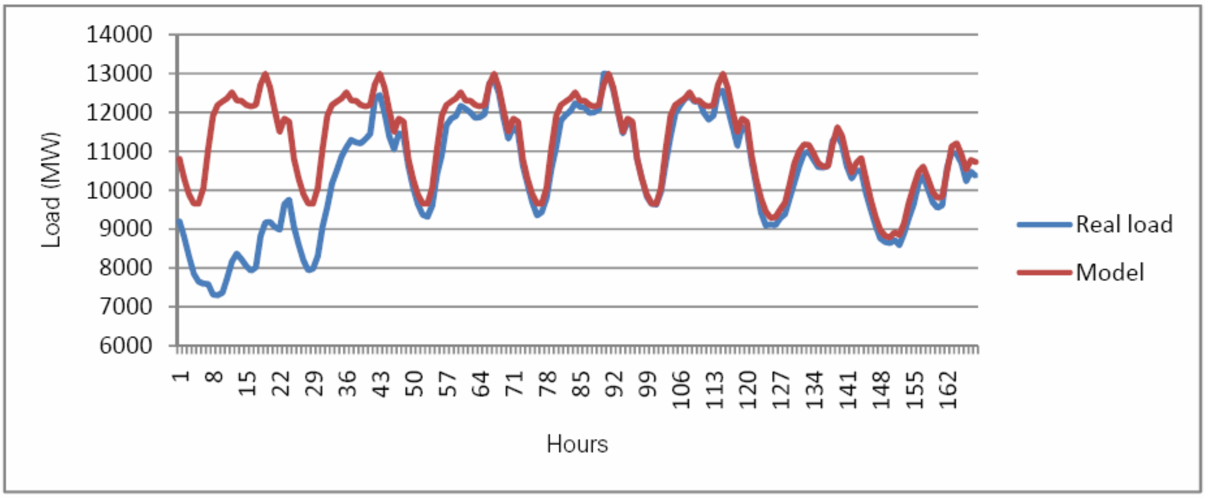

Figure 11: Hourly load evolution (first week of 2007)

The deterministic evolution is somewhat weak when it comes to model the various events that can affect a single load. As we just saw, exceptional conditions that only last for a while are badly modeled despite they are essential in any reliability assessment analysis. Therefore we can partly and locally model this unordinary behavior by adding to each bus load a random component with a zero mean value. As strong fluctuations from the nominal load are less frequent than small ones, a Gaussian variable (with $\mu=0$) is a good approximation. Standard deviation σ can vary depending on the load; for the sake of convenience we will first estimate it as 5% of the peak load value. The addition of a random component to the deterministic load evolution at a single node is shown on Figure 12.

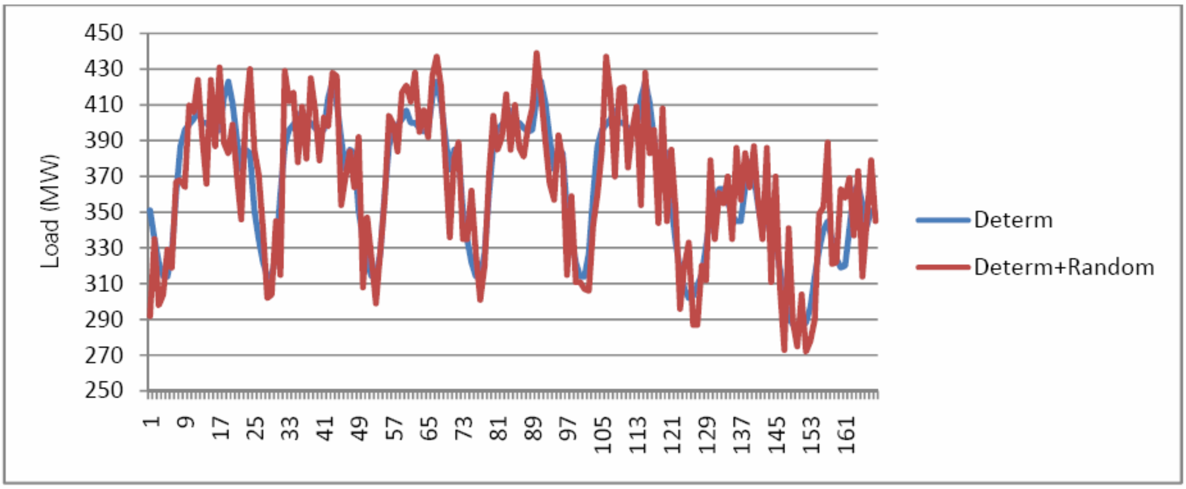

Figure 12: Addition of random component to the deterministic load evolution at a single node

Even with a random component, the load evolution we modeled can be somewhat different from real load evolution. Indeed plants, offices and home can have very different patterns of load evolution. Just think to plants that are closed on the week-ends working on 1, 2 or 3 shifts. Modeling these different types of behavior with different modulation diagrams would only be possible if we know the type of each load (plant, distribution network, offices, etc.).

Boolean state generation model

The general goal of the Boolean state generation module is to establish, for each network state, which elements are available and which are not. This is essential for a reliability assessment analysis because scheduled and forced outages are common events that can affect heavily the control of a complex transmission system. **Scheduled outages** (mostly linked to maintenance) are often planned months ahead. Thus, reliability assessment studies are performed to ensure that the shutdown of an element will not jeopardize the security of supply. However, networks are often controlled near to their operational limits and even scheduled outages can sometimes endanger the security margins (in Belgium, especially during the winter). On the other hand, **forced outages** (mostly linked to incidents) cannot be planned. When they occur in the very high voltage (VHV) network, they require a fast and coordinated answer from the European transmission system operators (TSO). If not, they can lead to more severe situations, e.g. the European blackout that occurred on November 6, 2006. In our reliability assessment study, scheduled outages will be modeled deterministically. For forced outages, a mix of deterministic and probabilistic approaches will be used. Security criteria have been fixed on a European level (UCTE) to prevent this kind of situations, e.g. the "N-1 criterion" that recommends the network operators to remain reliable after the loss of their biggest element (i.e. their greater power plant, a 380kV line, etc.). However, at the scale on an entire network, we must take into account the eventuality of the loss of several elements. That's why Monte-Carlo simulations are particularly useful when modeling this kind of unusual but extreme conditions. Indeed, it is unrealistic to consider all the possible network states of a national network with more than 3500 elements that can either be available or unavailable for the Belgian network. However, randomly selecting a subset (say, 100000) of these network states for our reliability assessment analysis would already give us a very good view of the network general behavior. Our Boolean state generation model has the double advantage to take into account both the probabilistic occurrence of incidents (with a random draw among the network states) and the Markovian (thus, deterministic) evolution of Maintenance and repairing (the element will be unavailable during the whole maintenance/repairing time).

Wind power input model

Together with the load and the network states definitions, wind power infeed is the third input of the rEliability assessment analysis. Actually, the entire study's purpose is to model the impact of this particular input on the network behavior. As for load and unavailabilities, wind power infeed id considered on an hourly basis. Our purpose is to evaluate the impact of offshore wind power; therefore, we must obtain as an input the hourly wind power productions of the offshore wind farms we want to consider. ESAT-Electa has developped wind speed Markov chains. Roughly speaking, Markov matrices have been created with statistical data (provided by RMI – Royal Meteorological Institute) on several Belgian places, among them Middelkerke (on the Belgian seaside). These matrices describe the probability that, during different hourly network states, wind goes from one specific speed range to another. As the wind behavior is not completely random but knows daily and seasonal variations, the wind model has taken into account different day/night and seasonal patterns for wind speed evolution, leading to different Markov matrices. Markov chains do consider a "memory" effect as each hourly wind speed value is dependent on several previous values. Thus, the temporal correlation of wind speed measures on a single place is taken into account; Markov chains are therefore a good compromise between the random behavior of the wind and its daily/seasonal patterns. Nevertheless, the model do not consider a correlation level between wind speeds in two different places – that is, if wind has a certain behavior in a certain place, then it will be very likely to have a similar behavior (but not exactly the same) 10 km away from this point. Thus, we can either consider a total correlation between two wind farm sites (exactly the same evolution) or a zero correlation level (independent evolutions). On the Belgian offshore level, we will obviously consider the wind power productions to be completely correlated as the offshore wind farms will be very close to one another. When wind blows over a wind farm, the entire power production is not exactly the power production of one single turbine, multiplied by the number of turbines. Indeed, the turbines geographical dispersion introduces a smoothing effect in the wind farm power curve, comparatively to a single turbine power curve. However, as our study analyses network states that last 1 hour, we can assume that the average wind speed will be the same for every wind turbine inside a single wind farm. To take into account the temporary disparity of wind speeds inside a wind farm, we should consider shorter network states (say, 10 min instead of 1 hour).

3.2.2.2 Processing

Now that we have all the inputs necessary to run the risk assessment analysis, we have to establish the specifications that will model the weekly and daily scheduling of the generating facilities. These are:

- **The Hydro Park Model**. The algorithm models two main functions of the hydroelectric facilities: peak shaving and wind balancing.
- **The Unit Commitment** (UC) **Model**. The algorithm models the scheduling of the remaining thermal units.

After this, the load flow is processed automatically. A rescheduling – load shedding algorithm must also be put in place, as well as a mechanism that manages tertiary reserve. Remember that two options exist for the Processing part: coding all the algorithms in Matlab or using a dedicated program. This last option could save a lot of time, because an integrated program will take many factors into account – actually more than we can do is a tight timeframe. Thus, we present here the nitty-gritty of the functions that should be coded, if coded in Matlab, knowing that any adequate risk analysis program will ensure a more complete analysis (and therefore, more accurate results).

Hydro Park model

Two types of hydro plants are commonly used to generate large amounts of electricity: hydroelectric dams & pumped storage hydroelectric. Whereas dams can be used both as a base load or a peaking power plant, pumped storage plants is solely used as peak shaving units. In many places, pumped storage hydroelectricity is used to even out the daily generating load, by pumping water to a high storage reservoir during off-peak hours and weekends, using the excess base load capacity from classical thermal sources (gas, nuclear, etc.). During peak hours, this water can be used for hydroelectric generation, often as a high value rapid-response reserve to cover transient peaks in demand. Pumped storage recovers about 75% of the energy consumed, and is currently the most cost effective form of mass power storage. Indeed, it produces electricity when prices are high and consumes power when prices are low.

Pumped water systems have high dispatchability, meaning they can come on-line very quickly, typically within 15 seconds, which makes these systems very efficient at soaking up variability in electrical demand from consumers or from wind generation. A hydroelectric dam originally built to provide base-load power will have its generators sized according to the average flow of water into the reservoir. Uprating such a dam with additional generators increases its peak power output capacity, thereby increasing its capacity to operate as a virtual grid energy storage unit.

The hydro park is modeled here to provide 3 main services: base-load generation, peak shaving and tertiary reserve. One can determine which part of the energy stored in the reservoir has to be allocated to each service. A fourth service will also be ensured by the hydro park in our model: wind balancing. Basically, it consists of allocating a part of the turbines power (and energy stocked in reservoirs) to the compensation of wind power hourly variations. This service can be provided either by hydroelectric dams or pumped storage plants. More precisely, a daily prediction of wind power production will be established 24h ahead. A daily rescheduling of the weekly unit commitment will then take wind into account. Finally, the hydro park will compensate the discrepancy between prediction and actual wind power production. One will have to decide, among the existing softwares, which one has the most satisfying model for the hydro park scheduling. Remember that 2 different scenarios have to be considered:

1. A scenario with no consideration for wind production. In this scenario, no wind prediction is made for the next day. Plant scheduling is done on a weekly basis (unit commitment, see below), as nothing apart from forced outages comes to modifying the weekly production planning.
2. A scenario with wind prediction: daily prediction (with a prediction error that must be estimated), daily power plant rescheduling and wind balancing from the hydro park. The general idea is to prove that generation cost is higher when wind fluctuations are not taken into account, as a real-time rescheduling has to be done by the other generating facilities (both hydro park and thermal power plants). This is the scope of Task7.

Unit Commitment model

Unit Commitment is likely to be entirely done by the software that will be purchased in January 2009. Therefore, it is useless to detail here with details the functioning of a classical unit commitment algorithm, as documentation can be found for every unit commitment software. Basically, it consists of planning the hourly production of every plant so that the overall generation cost is minimum, taking into account the startup and shutdown costs. Thus, unit commitment consists of an optimization under constraints. Moreover, our present unit commitment model has no specific feature, as this was the case of the hydro park model. However we would like to model the possibility of both a weekly and daily scheduling of the generating facilities (the second one takes wind prediction into account). Thus, two scenarios will be analyzed:

1. Weekly scheduling taking planned outages into account + Daily scheduling taking forced outages into account

2. Weekly scheduling (planned outages) + Daily scheduling (forced outages & wind predictions).

Further improvements could include a multi-producer model that would take into account the energy exchanges, made possible after the European electricity market liberalization.

3.2.2.3 Post-processing

Post processing consists of both making a statistical analysis of each state results and displaying these results in a friendly GUI (graphical user interface). This display will possibly be done by the software bought by BEAMS. However, part of the display process might have to be coded in Matlab.

3.2.3 Analysis of existing software

We have analyzed the possibilities of the following software dealing with a function of risk assessment : Assess, Scanner, DIgSILENT Power Factory, Neplan and PSS TPlan. On base on that analysis, the decision was taken to buy a research license of DigSILENT Power Factory (10.000€) which will be used to verify the effect of the network constraints for the integration of a maximum of wind capacity for a given level of reliability and security.

4. Recommendations

While recommendations resulting from phase 1 are concerning ways to improve wind power value for individual wind park owners. The second phase of the project deals with researching and increasing the upper-limit of aggregated wind power capacity in Belgium. Recommendations in this phase will therefore emphasize on security of supply.

4.1 Economic value of wind Power

First of all, it is important to encourage research and further improvement of wind power predictions, this as well on day-ahead as on intra-day basis. Gate closure is now at 14h00 D-1 which means wind power producers have to forecast output 10 to 34 hours before real-time. Three more hours have to be added to this horizon if the Belpex day-ahead market (closes at 11h00) is used to take positions in the market. With the emergence of intra-day trading and markets, accurate predictions until 5 minutes before real-time become important [6]. Better forecasting accuracy on these time horizons reduces imbalance volumes and associated costs and thus improves wind power value.

Liquidity on the different markets has to be improved. With more liquidity on the day-ahead market and intra-day market, BRPs having wind power in their portfolio will be better able to balance their positions before and after gate closure. When balancing markets become more liquid, this will reduce costs for the TSO when acquiring balancing services. This cost reduction will be benefited by the BRPs charged for imbalance costs. Liquidity on these markets can be improved by increasing available production capacity in Belgium (especially flexible capacity for intra-day and balancing markets). This can be attained by investing in local capacity, expansion of cross-border capacity or improving competition in the market.

Interconnection with other countries will lead to a better security of supply and will introduce more flexibility to smooth wind power fluctuations. It will also lead to improved competition, liberalization and trade which will it reduce price peaks and imbalance costs. Encouraging more flexibility in the power system can also be done by local investments in flexible generation units, energy storage, energy management and demand side management.

4.2 Security of supply

A general conclusion made during this research, is that Belgium should not be operated as an island when assessing technical upper limits for the integration of wind power.

Generation capacity in Belgium is steadily growing to be insufficient. The use of the pumped hydroelectric storage (PHES) is important both in terms of capacity provision and balancing capacity. These balancing possibilities are restrained in Belgium. The PHES offers a cheap balancing option but apart from that, it is mainly combined cycle gas fired power plants or fast-starting peak units that are used for balancing purposes. In some cases, shedable load contracts can be applied. With more wind power in Belgium, more balancing capacity would be needed in a country where already relatively high volumes of spinning reserves are kept. This might prove problematic.

Before even looking at the grid issues in the Belgian power system, it is recommended that the balancing opportunities with the neighbouring countries are fully used. Additional transmission capacity can help us in that matter. Next to more connections with other countries, the further development of Belgian generation capacity needs to be encouraged. With increasingly performing and flexible new technology power plants, more balancing options become available in a wider variety. These conclusions confirm those ones made in de first phase of the project.

The two separate issues of wind power, namely its variability and relative unpredictability can to some extent be treated separately. The former gives rise to a need for power plants that can easily adjust their output to the fluctuating wind speed profiles. A power plant's ramp rate and partial load efficiency constitute the most important parameters in this optic. These two elements will also be covered in more detail in task 7. The relative unpredictability is related to the forecast error of wind power. To cover this, reserve capacity is needed. This stands in relation with the correlation between the different wind farms, other generation capacity and demand forecast error. This reserve capacity can best be seen in two directions. Wind power forecast errors occur both in negative and positive direction. When an underestimation is made of the wind power output, a flexible downscaling of active production can avoid curtailment of the wind energy. An overestimation can be covered by available spinning reserve capacity.

A geographical distribution of wind power can help improving the impact of both variability and relative unpredictability. Again, interconnection with other countries becomes important on this matter. The development of a central monitoring system for predictions and real-time output of wind energy (cfr. Control Centre of Renewable Energies (Cecre) in Spain by Red Eléctrica) on national or international level has to be encouraged. This will lead to an aggregation of predictions and therefore improve integration of wind energy on a secure way. Anticipation (to events, to incidents, to large differences between real-time production and prediction…) becomes possible and reserve requirements and associated costs can be diminished.

5. Perspectives towards phase 3

In a third phase of the project, economic possibilities facilitating integration of wind power will be analyzed. Several regulatory and market based mechanisms are feasible when trying to support wind energy systems. The support can be based on the power installed, without looking at the energy generated, or on the actual energy delivered. In the long run, wind energy should become an integral part of the electrical energy market, without requirements for special support.

Therefore, this project will not look at generally known support mechanisms as green certificates and feed-in tariffs but will try to develop a framework that allows wind power to join the regular market without such additional support. As power output prediction is far more difficult even accounting for the weather prediction improvements that are part of the research of phase 1, a grid operation and settlement system that can accommodate short-term variations would very much support wind energy in the grid. Therefore, this part of the research in phase 3 tries to find out what the framework should be.

The first part is the settlement. If the time to gate closure is shorter, the inaccuracy in wind prediction is less important. As such, there is a close link between predictability and market value. Several countries already give no specific gate closure arrangements and balancing advantages for wind power. Therefore, the research will try to find out the best gate closure arrangements as a function of the accuracy of the wind prediction. The result will depend on the type of wind energy system used, especially the behavior at high wind values, and on the time spread of the wind output. Using different stochastic tools, the Loss of Load Probability (LOLP) is calculated for different prediction accuracies and gate closure timing.

Another possibility for simplifying the task of the wind energy operators is that they can pool their output and supply with other market participants that use different type of power generating units (for instance controllable or pumped hydro or fast reaction gas based power plants). The use of active demand side management (loads that can be switched off on demand) may be also part of this approach.

A last approach may be found in an adjustment market, as found in the some Scandinavian countries. The so-called ELBAS market allows market participants to submit bids up to one hour before actual delivery. Such bids are anonymous and thus more interesting for wind energy generators.

The analysis of all market elements has to start from the LOLP-method, in which it is analyzed what the Loss of Load Probability is under certain grid conditions. The input from the wind energy is introduced via a statistical approach in which the improved wind energy prediction is taken into account stepwise. From the LOLP-results that account for the dynamic behavior of the remainder of the power plants in the control area, the required balancing power is found. The impact of the other measures of market arrangements is introduced for each case, as they reduce the dynamic requirements for the remaining power plants, for instance as short term available balancing power may be used (pumped hydro, boost of Combined Cycle gas power plants). The remaining uncertainty has its impact on the price setting. Therefore, the simulation tool has to be able to assess this problem and to find the impact on price setting in the adjustment market. Stochastic tools exist to find this relation and will be used here.

The final phase contains three tasks. First, different alternatives of balancing power for non-nominated power variations. These include large hydro-storage, dynamically controlled gas-fired power plants, decentralized storage and shifting demand. The technical parameters for the above-mentioned measures will be listed. The different measures are all more or less developed in terms of technology. Moreover they differ significantly in price and efficiency. Therefore, based on the inventory, the most promising measures for the given context will be selected. However, no market mechanisms are in place today for procuring power from these measures. Therefore, the second task also contains the development of market mechanisms for procuring these services in an unbundled market. The final task of the project, Based on the results from phase 1 and phase 2 and taking into account the results from Task 7, the integration of large amounts of wind power in the power system will be assessed. The policy objective of a high amount of wind power which should be integrated in a way that is conform with the European internal electricity market is checked with regard to the boundary conditions set by the requirement for security of supply.

A sensitivity analysis will be carried out with the tools as developed in Phase 1 and 2 determining the following parameters:

- Adequacy of supply (LOLP-probability).
- Greenhouse gas emissions (Kyoto Protocol: CO2 and other emissions).
- Green certificate markets (requiring maximum wind farm operation, including different minimum prices for such certificates).

Offshore wind power and 30%-rule?

Today, regulation in Belgium states that offshore wind parks receive a tolerance margin of 30%. This means that deviations from nominated wind power output will not be subject to imbalance settlement if staying within this margin. These deviations will however be sold or bought by Elia at 108/92% of the market price. An extra question to be raised in this project, is if there is a technical ground for this 30% imbalance exemption for offshore wind energy in Belgium? In a first step the functioning of imbalance settlement for offshore wind power is explained. Next, the technical parameters determining the imbalance of wind power are examined to investigate the technical reasons for this exemption. This happens on three fronts.

First, a wind speed forecast error for offshore wind is made. This will show whether larger forecast errors can be expected offshore. Apart from pure wind speed analysis, the transformation to electricity through the wind turbine power curve is also introduced. It can be expected that the increased steepness of a 5MW turbine compared to a 2MW turbine will have an impact on the forecast error.

A second analysis will use a reliability model to investigate the impact on balancing options in the system in terms of reliability. This becomes especially interesting when the system is congested. Cheap balancing options such as the PHES in Coo might not make it all the way to the Belgian coast.

This same congestion analysis can also be made using the MILP-model applying the UC/dispatch approach to look at how the system reacts to imbalances and which power plants provide the balancing reserve for offshore and onshore wind power, especially when the system is congested.

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