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

"WINDBALANCE"

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Energy

FINAL REPORT

Balancing wind energy in the grid: an overall, techno-economic and coordinated approach "WINDBALANCE"

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TABLE OF CONTENTS

EXECUTIVE SUMMARY

A. Context

As part of the European energy policy goals of sustainability, security of supply and improved competitiveness, the share of Renewable Energy Sources for Electricity (RES-E) is rapidly increasing. The Belgian national renewable energy action plan to comply with the EC renewable energy directive (2009/28/EC) estimates the installed capacity of wind power at 4320 MW towards 2020. This is expected to account for a yearly generation of 10.5 TWh, being 9% of the reference electricity demand scenario for 2020.

B. Objectives

The general objective of this project is to study the potential for massive wind integration in Belgium. Technical, economic and regulatory boundaries for a reliable and efficient integration in the power system are identified, together with necessary measures to transcend them.

C. Conclusions

Phase 1: market value of wind power

In the first phase of the project, a market simulator is developed to determine the costs and revenues for a wind power generator. This simulator serves as a tool to calculate market value that wind power yields in different markets under different market conditions and depending on the predictability of wind power output. The developed market simulator calculates the value of wind energy when traded on the local power exchange, i.e. Belpex Day-Ahead Market. Real-time, wind power prediction errors are settled with the imbalance tariffs imposed by the TSO. Abstraction is made from the additional revenues from green certificates which are currently settled at minimum prices between 90 – 107 €/MWh.

The value of wind is expressed as the “Fixed Price OTC Equivalent” and is compared to the fixed price negotiated in Over-The-Counter (OTC) contracts. This simulator is therefore a valuable support for valuating wind power investments or negotiating OTC-contracts. Moreover, the tool provides a base of an objective analysis of the real market value of wind energy under different market conditions and is therefore also a valuable tool for policy making.

The simulator is validated for different configurations for wind power generation: for a single turbine and an average Belpex Day-Ahead Market price of 75.3 €/MWh, the fixed OTC-value for 2009 is determined at 66.3 €/MWh. The limited predictability of wind therefore leads to a revenue loss of 18% due to imbalance settlement.
It is found that this OTC-value can be increased with 16% when aggregating wind generation over larger areas and submitting this as one nomination (cfr. Germany). Secondly, different nomination strategies are researched including the value of accuracy improvements concerning forecasting. For a wind farm of 8 MW, the OTC-value is determined at 68.6 €/MWh, including the imbalance loss of 14%, when using state-of-the-art prediction tools. The value increases with 5.5% when using intraday markets to adapt nominations to newer predictions.

As the tool was developed with data up to December 2008, resulting values and prices are rather high compared to the actual value in 2009-2011 (effect of the global economic crisis). The results below can therefore be best compared in a relative manner.

Phase 2: technical upper limit for wind power in Belgium

In the second phase of the project, constraints concerning the back-up of wind power in Belgium are studied. A simulation model, representing the short-term operation of the Belgian generation park, is developed and used to assess the limits of wind in the Elia control zone (Belgium and Luxemburg). All available power plants are assumed to be used in a cost-optimal way to cover demand in the control area. In first instance, network constraints and potential grid bottlenecks are not considered.

Under these assumptions, technical barriers for wind are determined by the capacity of other available generation units to set off wind generation prediction errors. Overestimation of wind generation needs to be balanced by flexible capacity. These reserves can be activated to meet discrepancies between demand and supply. Underestimations result in identical requirements but can be resolved by wind generation curtailment when necessary. Results show curtailment of up to 7800 MWh for 24h for an installed wind power capacity of 3000 MW, depending on demand and wind power generation profile. Besides the technical barriers of integrating large shares of wind capacity in the system, the impact on operation costs and greenhouse gas emissions are determined.

Within Belgium, the potential of the generation system to balance variable generation by wind farms is limited. This barrier could be relieved by considering the whole of Europe, while making abstraction of potential grid bottlenecks. Combining power systems reduces the required reserves when separate system imbalances show limited or opposite correlations. Literature shows that wind power fluctuations and prediction errors can be smoothened when aggregating them over larger regions.

The assumption that no transmission bottlenecks are present in the Belgian and European grid is clearly an enormous simplification of reality. Therefore, one of the project deliverables focuses on methodologies for including detailed network simulations. Due to practical constraints, there has been opted to work with a DC load flow model serving as a simplification of AC load flow simulations.

Phase 3: balancing large wind power variations in Belgium

The final phase of the project focusses on the facilitation of massive wind power integration scenarios in the Belgian power system towards 2020. Focus is put on technologies and market mechanisms to cope with wind power variability.

Balancing technologies

Four main technologies with balancing potential are studied and assessed: first of all, large (pumped) hydro power plants are a very attractive option to overcome the variability of wind power as this technology is characterised with high flexibility and low operating costs. However, due to geographical constraints, their potential is limited in Belgium. Two pumped storage plants are currently present in Belgium with a capacity of 1164 MW (Coo) and 224 MW (Plate Taille). New innovative concepts are currently under research e.g. offshore ‘energy islands’ pumping water out of a reservoir resulting in electricity generation when allowing the water to flow back in trough generators.

However less flexible, combined-cycle power plants (CCGT) or peak power plants are generally assessed to have significant wind power balancing capabilities. CCGT plants can be started in 40-150′, achieve reasonable ramp rates and efficiencies. Peak power plants (turbojets, gas turbines and diesel motors) are characterised with higher flexibility (start-up, ramp rates) but lower efficiencies. The gas turbine starts generating power after 3′ and reaches full capacity in 6′.

Finally, two innovative concepts showing potential in balancing future wind variations are introduced: decentralised storage and demand response. Energy storage systems, characterised by prompt response and limited deployment time, can offer additional balancing capacity to the system. A large variety of storage technologies is currently

available and under development showing a wide range of technical and economic characteristics. In contrast, demand-side response enables balancing capacity by means of shifting demand of consumers. In Belgium, first estimations veils a potential of 358 MW, only contracted from domestic appliances. This number is based on a minimum level of acceptance by consumers.
With the expected future integration of plug-in electric vehicles, the annual household consumption may double resulting in an important future potential, both for storage and demand response.

Market mechanisms for balancing wind

In most European power system, e.g. Belgium, wind power faces a market context implying balancing responsibility. Final responsible for balancing the overall system is the Transmission System Operator (TSO), (de)activating reserve capacity to restore the real-time balance between demand and supply. The costs of these balancing services are transferred to the responsible market players (BRPs) by means of imbalance tariffs. This implies additional costs for wind generators facing the limited predictability of output. This balancing responsibility for variable RES-E is an ongoing policy discussion.

In order to cope with uncertainty in their portfolio, BRPs in Belgium are able to apply different market mechanisms. As accuracy of predictions increases with closer prediction horizons, balancing costs can be reduced by enabling possibilities to adapt nominations intraday. Market mechanisms are designed enabling this with intraday trade and power exchanges. Intraday markets were introduced in Belgium as from 2008 and expanded with cross-border allocations. However, these markets remain characterised by low liquidity. This is expected to be improved with increasing market integration and competitive environments, and the physical availability of new flexible capacity.

Special attention is given to a particular Belgian regulation exempting offshore wind partially from the existing settlement mechanism. Generation deviations inside a margin of 30% of the nominated output benefit from capped imbalance tariffs. A preliminary study confirms a prediction error (RMSE) which is 2-6% higher for offshore locations. Although this regulation can be defended as it directly tackles the imbalance cost, this support mechanism is complex and not transparent. Capping the imbalance settlement tariffs weakens the link between the reserve market and the imbalance tariff, being a prerequisite for the well-functioning of balancing markets. Therefore, this support mechanism should rather be replaced by increasing the minimal price of the green certificates. This increase is estimated at 1.4-1.7 €/MWh.

Facilitating high wind development scenarios in Belgium

In view of meeting renewable energy targets towards 2020, the Belgian national renewable energy action plan targets an installed capacity of 4320 MW in 2020. The impact of this scenario is researched by means of the simulation model representing the short-term operation of the Belgian generation park.
The model is therefore extended with network constrains through DC load flow. Wind is integrated in a model representing the Belgian power system including scheduled investments towards 2020. In addition, four cases are designed representing different combinations of balancing technologies.

First simulations reveal major integration problems as the generic model seems to be unable to facilitate the 4320 MW of wind distributed over the Belgian control zone. Firstly, certain network constraints occur in the coastal region, due to large offshore capacities, and in the South of Belgium, due to a less meshed grid. A series of additional grid reinforcements are proposed and included in the model. A second barrier for large wind power integration is the alleged inflexibility of the nuclear park as currently operated (in base load). Low demand combined with high wind generation may result in net demand lower than the base load nuclear park. Therefore, this study proposes to increase flexibility of the generation park by operating the nuclear power plants in modulating mode (cfr. France). A final barrier originates from the large imbalances which may occur due to wind-forecasting errors. Predefined capacity of 300 MW spinning reserves and 737 MW non-spinning reserves may not be adequate to balance wind power imbalances. Increasing the amount of reserves in order to be able to cover the largest possible forecast error may be unrealistic in the framework of generation adequacy. Therefore, in a final step, import and export are allowed in real-time at artificial high costs. This maintains the incentive to cover imbalances on a national level.

Results for the reference scenario reveal that nuclear regulation is needed mostly when a high wind power output is present during low demand. Furthermore, peak power plants are used regularly in all scenarios when only 300 MW of spinning reserve capacity is demanded from the system. Also import is required in order to balance the largest forecast errors. Export on the other hand is not used because nuclear power is assumed to be able to regulate its power output down to 60% of its nominal power. Increasing the amount of spinning reserves to 1055 MW reduces both the use of peak power and the import requirement, leading by consequence to a more secure Belgian power system.

In this study, the focus is put on the ability of the power system to balance wind power with national resources. The use of peak power plants and import is seen as a "problem" for security of supply and represent additional reserve capacity. Three technology cases, representing CCGT, decentralised storage and demand response, are therefore compared with the base case on this use of standing reserve capacity and import. Additionally, operational efficiency is investigated.

Due to fact that the model works on an hourly time-scale and spinning reserves are held constant to 300 MW, adding extra CCGT power plants will have no effect on the flexibility of the Belgian power system in balancing forecast errors. Adding in a third case decentralised storage units to the Belgian power system does not change the results to a significant extent. This is due to the small amount of decentralised storage added to the Belgian power system and the fact that a large amount of wind power integrated in the Belgian system (4320 MW) leads to some extent to large changes in power output. These large changes cannot be covered by such a small addition of decentralised storage. However, storage can still have an important economic impact on daily situations. Extending the amount of decentralised storage would probably yield more extended results, but is expected as difficult to obtain towards 2020. Last but not least, the base case is extended with 1000 MW of demand response: also in this case, the output of the model shows no significant difference in operational efficiency. The use of non-spinning reserve capacity and import decreases however in all scenarios considered, meaning that demand response is of good help in balancing wind forecast errors.

D. Contributions to the scientific support of a policy towards sustainable development

The integration of a large share of wind energy is, because of variable production and limited predictability, a major challenge for the current electricity system. This integration is limited by technological, economic and regulatory realities based on a system of conventional and centrally located generation unit. The contribution of this project is to identify these barriers and to offer solutions. The results of this project can be used by the Belgian policy makers to increase the potential for wind energy.

One of the results represents a market simulator that allows to assessing the impact of competition on the profitability of wind energy. Furthermore, a simulation model is developed to evaluate the impact of wind on the entire system. Finally, technologies and market mechanisms are offered to help balancing generation and demand with the variable output of wind. These are integrated into the developed tools.

E. Key words

Balancing, grid integration, market integration, wind energy

ACRONYMS, ABBREVIATIONS AND UNITS

BRP	Balancing Responsible Party
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
CIM	Continuous Intraday Market
CTPM	Cumulative Transition Probability Matrix
DAM	Day-Ahead Market
DR	Demand Response
DSR	Demand-Side Response
DSM	Demand Side Management
EC	European Commission
ED	Economic Dispatch
LOLE	Loss of Load Expectation
MILP	Mixed Integer Linear Programming
NREAP	National Renewable Energy Action Plan
OTC	Over-The-Counter
TSO	Transmission System Operator
TPM	Transition Probability Matrix
RES	Renewable Energy Source
RES-E	Renewable Energy Source for Electricity
RMSE	Root Mean Square Error
UC	Unit Commitment

1. INTRODUCTION

1.1 Research context

As part of the European energy policy goals of sustainability, security of supply and improved competitiveness, the European Commission imposed ambitious targets for its member states concerning the development of renewable energy sources (RES). Under Directive 2009/28/EC, these sources of energy are expected to bear 20% of the final European energy consumption by 2020. For electric energy, this yields a figure of 33% of the final electric energy consumed by 2020 renewable sources. These environmental ambitions are to be integrated in a way which does not compromise security of supply (Directive 2005/89/EC) and is compatible with the internal market (Directive 2009/72/EC).

Based on gross domestic product, current installed capacity and RES potential, the national target for Belgium is set at 13% of gross national consumption. In comparison, the share of renewable energy in 2005 only accounted for 2.2%. According to the Belgian national action plan for renewable energy, presenting the strategy for reaching the 2020-target, the largest contribution is expected to be delivered by the electricity sector with a share of 20,9% RES. In this sector, wind, above solar PV and biomass, is seen as the highest potential for renewable development. The national action plan for renewable energy, developed to comply with Directive 2009/28/EG, targets an installed wind capacity of 4320 MW by 2020 (ENOVER/CONCERE, 2010).

Challenges for wind power integration

Wind power, depending on a variable resource, is characterised by a limited controllability and predictability. This is expected to lead to various power system integration challenges described in European and national integration studies: EWIS (European Wind Integration Study 2010), DENA Grid Study I & II (2005 & 2011), National Renewable Energy Laboratories (GE Energy, 2010), etc. These issues can be classified under network adequacy, operational efficiency, generation adequacy, ancillary services and system stability.

A first set of barriers are classified under network adequacy. The electricity grid imposes specific challenges on wind power developments. The connection of wind turbines may require for instance grid reinforcements. New wind farms are often built in remote areas far from main demand centres. New transmission capacity therefore becomes necessary to transport the electrical energy to where it is consumed.

The variable contributions from wind power must be balanced with other generation capacity possibly 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 I (dena, 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 substantial parts of the transmission network. Consequently, 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 new overhead lines and the delay that this undoubtedly will cause in system build-up.

Secondly, variable Renewable Energy Sources for Electricity (RES-E) are expected to impact the operation of the generation system. Scheduling and dispatch of conventional generators will be affected by variable RES-E integration as cheap electricity (low variable cost) enters the merit order. This may replace conventional generators saving overall fuel and CO_2 costs. On the other hand, variability and the limited predictability require flexible capacity to cover occurring prediction errors with specific ramp rates. This may result in generators operating under optimal efficiency thus leading again to fuel, CO_2 and wear and tear costs. Moreover, peak power plants are expected to face reduced load hours which stress investments in flexible generation.

A third challenge is to maintain adequacy of generation, namely the ability of the generation system to meet peak demand in the long run. Although wind power plants can make a significant difference regarding the energy requirements of a power system, these plants may have a limited contribution in ensuring the power system requirements at all times due to their non-dispatchable nature. Depending on penetration level and system characteristics, wind capacity credit is found to vary between 5 - 40% (VTT Technical Research Centre of Finland, 2009).

To ensure a continuous and reliable grid operation, generators and system operators have to supply services that are generally denoted as “ancillary services”. These services deal with frequency and voltage stability, transmission security, black-start capability and economic manageability of the grid. Ancillary services do not directly deliver net energy, but are a necessity for the secure and reliable operation of the electricity system. Specifically relevant when considering wind power integration is reserve capacity is necessary to maintain the balance between demand and generation.

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

Balancing wind in power systems

Currently, the potential for wind power integration may be limited due to different technical boundary conditions of on one hand the electricity grid, and on the other hand the generation system to maintain the balance between demand and generation. Since electrical energy is difficult to store in large amounts, the latter becomes a major challenge when integrating variable RES-E. The TSO, as final responsible for grid security, requires all market players to submit scheduled injections and off-takes one day in advance. The nominations are to be balanced and real-time deviations from this balancing requirement are charged to the respective BRP. The resulting overall imbalances are covered by reserves available to the TSO. Corresponding costs are accounted to the responsible market player (Balancing Responsible Party, BRP) by means of the imbalance settlement mechanism (Tractebel & Katholieke Universiteit Leuven, 2009; Vandezande et al., 2010).

One of the issues hampering the integration of wind in the power system is limited predictability. Prediction errors lead to imbalanced positions and generate costs for the system or the wind power generators in case of balance responsability. As the accuracy of predictions increases when approaching real-time, market and regulatory mechanisms (postponed gate closure, intraday trading, etc.) enabling this possibility may be useful for wind power integration.

As predictability of RES-E will never reach 100%, flexibility in generation and/or demand is expected to be a prerequisite for wind power integration. However, wind can best be integrated in the power system if it becomes integrated in the market environment. This means market mechanisms are necessary enabling to procure this flexibility in a market conform way. 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 originally not adapted to variable non-dispatchable generation. This could hamper the integration of these RES-E in electricity markets. 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.

1.2 Research targets

The general objective of the WindBalance project is to identify the technical and market barriers limiting wind generating potential in Belgium, and to analyse how they could be removed. Consequently, the results and insights of this project assist Belgian policy makers in taking necessary actions to increase the potential of wind energy.

In a first phase of the project, a bottom-up approach is applied to assess the context in which a wind power plant currently operates. Costs and revenues are determined and assessed by means of a market simulator taking into account wind power generation, market prices and existing market mechanisms. This work allows to assess profitability together with the value of different measures and market mechanisms (e.g. improved forecasting, intraday markets, etc.).

In the second phase of the project, a top-down approach is used to determine the upper limit of aggregated wind power in Belgium. This is performed by using Unit Commitment (UC) and Economic Dispatch (ED) modelling to assess the flexibility in the system to cover unexpected wind power variations. Under these assumptions, the technical upper limit of wind is determined by the capacity of the other available generation units to offset the fluctuations in the wind energy generation and the potential for demand side management. The cost of this approach is assessed as well as the impact on CO_2 emissions. In this phase, focus remains on an isolated system without network constraints. In the remainder of phase 2, a methodology is developed to release these assumptions to allow a more realistic approach: the aggregation of different control zones is expected to positively affect the integration of wind power while network constraints are expected to reduce wind power potential. By means of the developed methodology, technical, economic and regulatory boundaries of wind power integration can be assessed properly.

In the third and final phase of the project, measures to remove barriers for wind power developments and to increase wind power potential in Belgium are presented. Different technologies, able to deliver additional balancing capacity to the generation system, are reviewed in detail: large-scale hydro-storage, dynamically controlled gas-fired power plants, decentralised storage and shifting demand. Technical and economic parameters are listed, compared and prioritised for further study.

The second step is to review market mechanisms to procure these services. Market mechanisms allowing the procurement of balancing capacity after gate closure time are reviewed in detail. Special attention is given to an existing market mechanism in Belgium partially exempting offshore wind power from their balancing responsibilities.

Implementation of this mechanism is assessed together with its motivation and financial impact.

The final step is to apply the developed system simulation model to assess the integration of 4320 MW of wind by 2020, targeted by the national action plan for renewable energy. Even when taking into account current scheduled generation and network investments towards 2020, serious problems are expected to arise. The objective of this part of the study is to analyse integration bottlenecks step by step while adding and evaluating necessary measures. Additionally, the impact of flexible technologies described in the previous tasks, are researched and their impact on generation adequacy (reliability) and operational efficiency (operating costs and greenhouse gas emissions) is evaluated.

1.3 Project overview

- Phase 1 (2007): modelling market operation of one wind power plant (bottom-up)
  - Task 1: overview current market framework for wind power
  - Task 2: stochastic description of wind power output and prediction error
  - Task 3: stochastic description of market data
  - Task 4: simulation tool for wind power in markets
- Phase 2 (2008): modelling wind power in the power system (top-down)
  - Task 5: technical upper limit for wind power without network constraints
  - Task 6: introducing network constraints
- Phase 3 (2009-2010): modelling measures for wind power integration
  - Task 7: balancing power for non-nominated power variations
  - Task 8: Integration of large amounts of wind power in the system

All individual task reports can be found on the project website:
http://www.esat.kuleuven.be/electa/windbalance/

2. METHODOLOGY AND RESULTS

2.1 Phase 1: simulation tool for wind power in markets

The main objective of the first part of the project is to develop a simulation tool for estimating the value of wind in power markets. This tool enables to perform long term estimates of the market value of wind by means of combining wind power generation with market prices. This enables the assessment of wind power investments, but also market design, as the developed simulation tool allows easy adjustment of input data and parameters e.g. the value assessment of extended gate closure, intraday markets, location, forecasting tools, etc.

The main objective of this task is to develop the simulation tool and to use it to estimate the value of wind energy using local power exchanges. Section 2.1.1 deals with obtaining data concerning wind power generation and market prices. A methodology is presented to construct synthetic time series of wind generation which can be used as main input for the simulator. Additionally, a survey is performed to review the availability of historical time series of prices on different markets. The simulation tool itself is presented in Section 2.1.3 and results concerning the value of wind power for different wind power configurations and prediction techniques are discussed in Section 2.1.4. In a final Section 2.1.5, some conclusions are put forward.

2.1.1 Data: wind power generation and market prices

2.1.1.1 Wind generation and predictions

One of the main inputs when assessing value of wind power is its active power output. As in Belgium, wind power is subject to imbalance settlement, also the active power predictions are to be taken into account. Historical time series of wind power measurements and predictions are probably the best data for market value calculations. They are however rarely available for individual wind power plants. Aggregated wind power generation and predictions over the entire control zone are sometimes provided by the TSO (e.g. Germany). This is not the case in Belgium.

As wind power output depends directly on the wind resources, an alternative is to obtain wind speed measurements and predictions from meteorological services and model the power prediction and measurement by means of the power curve of the turbine and other parameters representing a specific wind power plant. The accuracy of the results depends on modelling of these parameters but may serve as a good estimation.

A second alternative to represent wind generation data, and presented in this section, is to develop synthetic time series. A representative model of wind power generation and its associated uncertainties is developed in the framework of this study based on the stochastic behaviour of wind generation and its prediction error as a function of the prediction horizon. This model is based on historic measured and predicted wind power generation data.

Synthetic 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 publications on synthetic time series generation (Aksoy et al., 2004; Box et al., 2008; Manwell et al., 2006; Nfaoui et al., 2004; Sahin & Sen, 2001; Shamshad et al., 2005; Soens, 2005). Publicly available historical wind generation data and the corresponding wind power prediction data from the German TSO control areas are used for calibration.

A. Markov Chains

With 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 are then analysed 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. To this end the cumulative form of the TPM (CTPM) is needed, 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 of the transition probabilities to be 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.[1]

B. 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 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 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 1.

C. 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 2a). 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 from 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.

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

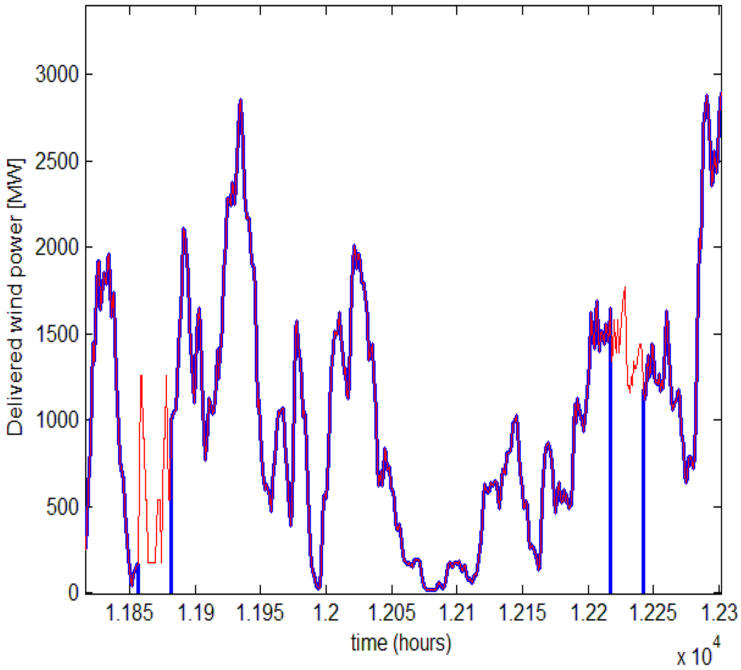


Figure 1: Illustration of gap filling (blue: series with gap, red: result)

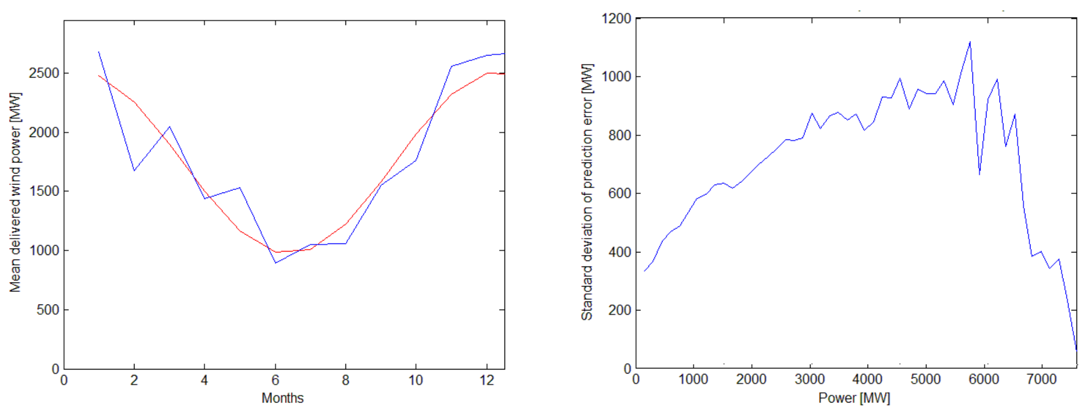


Figure 2: Mean monthly wind power values (a, left), Standard deviation of prediction error for different power levels (b, right)

The seasonal variations are tackled by computing a separate TPM for each month. Each time a month of data is generated, the specific TPM of 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.

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 3 and Figure 4, 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.

Diurnal variations are much smaller, and are therefore neglected in a first step. However, in a further step, they 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.

D. 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 power and market models.

In case 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.

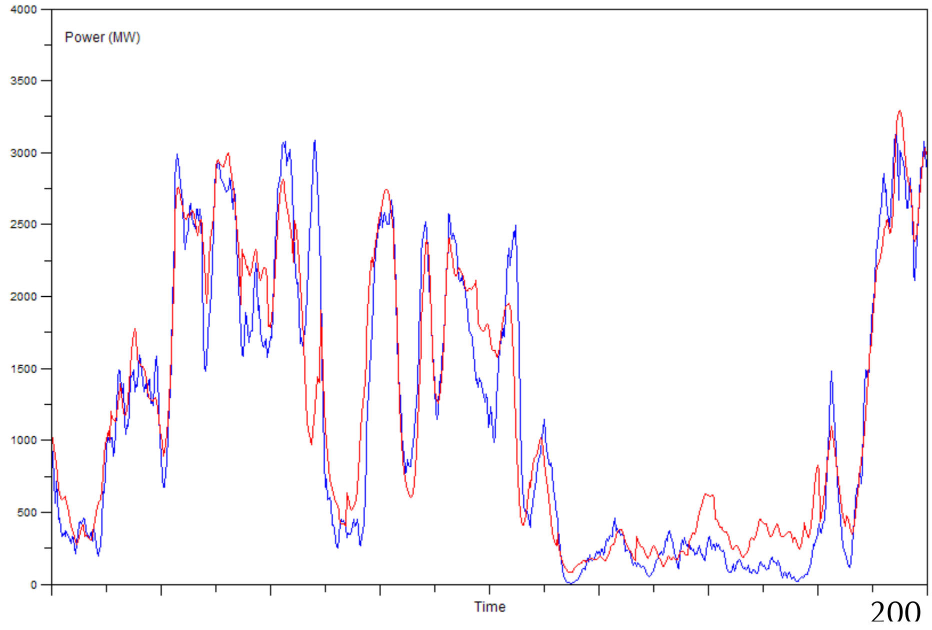


Figure 3: Input time series: wind power (blue) and predicted wind power generation (red)

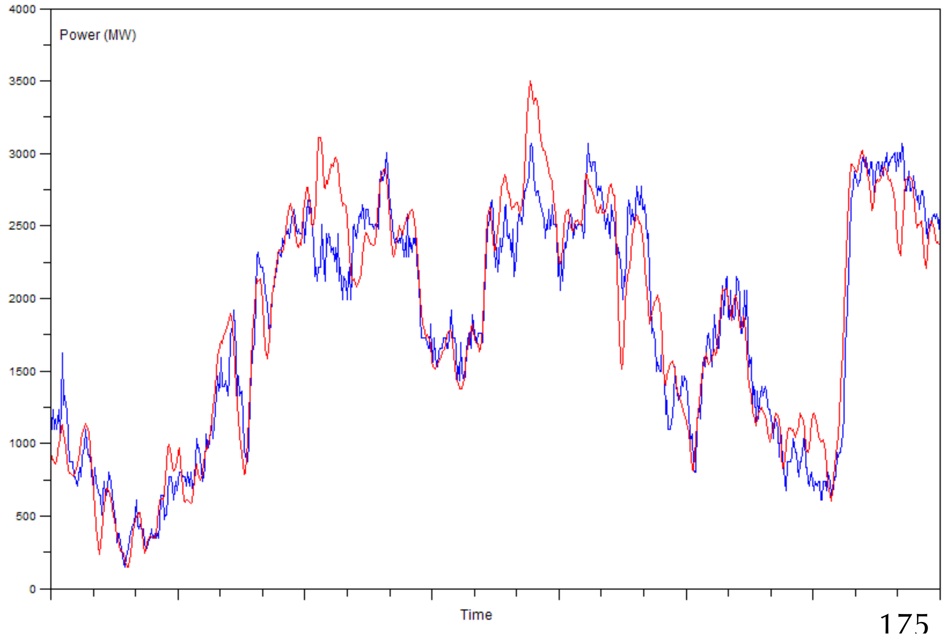


Figure 4: Generated time series: wind power (blue) and predicted wind power (red)

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 (Figure 2b). For the highest power levels the curve drops down again. There are three reasons for this. The main 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 generation output.

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.

E. Results

The results of this analysis are satisfying. The generated time series for wind power and prediction error are very similar to the time series of the input data. This can be verified in Figure 3 and Figure 4. Of course these figures are not identical due to the synthetic nature of the series in Figure 4. 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 important for power and market studies. The model serves as well for a single wind turbine, for specific wind farms as for entire regions.

2.1.1.2 Market prices

The market simulator developed in this project requires time series of prices to be coupled with wind generation and its prediction error. Historical time series of the Day-Ahead Market of the Belgian Power Exchange (Belpex) and the imbalance tariffs imposed by the Belgian TSO are obtained and implemented. Additionally, intraday market prices can be implemented to study the impact of intraday trading.

In 2007, ETSO (currently ENTSO-E) published the results of its legal survey on market transparency (ETSO, 2007). The compliance of all ETSO members with the transparency and the availability of reference market data is extensively dealt with in Task 3.

A. Day-ahead spot market prices

- Belgium: Belpex (www.belpex.be)

The Belpex Day-Ahead Market (DAM) was successfully released on 21 November 2006. It provides standardised products (hourly instruments) to sell and purchase electricity to be delivered the day after. Prices are based on a double-sided blind auction.

The Belpex DAM is coupled with the French Powernext Day-Ahead market and the Dutch APX-Power NL. In 2009, Belpex and Powernext were coupled for 67% of the time and Belpex and APX for 87% of the time. Belgium was only isolated from the two other markets for 2% of the time.

Historical data concerning traded volumes and prices can be delivered by Belpex upon request. The average price in 2010 was 46.3 €/MWh and traded volume was 11.8 TWh, which represented 15% of the total yearly consumption.

- Others:
  - The Netherlands: APX Power NL (www.apxgroup.com)
  - Germany, France: EPEX Spot (www.epex.com)

B. Intra-day market prices

When looking for historical data on intraday markets, it should be noted that by the start of this project, intraday markets were still relatively new. In Belgium, an intraday market, the Belpex Continuous Intraday Market (CIM) has been introduced on the Belpex platform on 13 March 2008, based on continuous trading. Historical data concerning traded volumes and prices can be delivered by Belpex upon request.

Despite measures for cross-border intraday trading with France, and later The Netherlands and the use of liquidity providers, volumes traded on the Belpex CIM remain relatively low. In 2010, APX-ENDEX, Belpex and Nord Pool Spot have agreed to establish an integrated cross-border intraday market.

- Others:
  - The Netherlands: APX Power NL (www.apxgroup.com)
  - Germany, France: EPEX Intraday (www.epexspot.com)

C. Balancing prices

- Belgium: Elia (www.elia.be)

Historical data concerning imbalance prices for the Belgian control zone are publicly available on the website of the Belgian TSO, Elia. Depending on the direction of the imbalance compared to the system imbalance, prices are based on the Belpex reference market price or on the price for up- or downward regulation (Table 1).

Table 1: Imbalance tariffs in the Belgian Control Zone (source: Elia, 2011) - imbalance in this table is defined as the measured generation minus the nominated generation. An underestimation of the production thus leads to a positive imbalance.

	Positive system imbalance	**Negative system imbalance**
Positive imbalance BRP	Max. 0.92 * Belpex DAM Variable tariff depending on: 1. Downward regulation volume 2. Average downward regulation price 3. Activated downward regulation price	0.92 * Belpex DAM (+) 1.08 * Belpex DAM (-)
Negative imbalance BRP	1.08 * Belpex DAM (+) 0.92 * Belpex DAM(-)	Min. 1.08 * Belpex DAM Variable tariff depending on: 1. Upward regulation volume 2. Average upward regulation price 3. Activated upward regulation price

DAM = Day-Ahead Market

Since November 2010, the tariff structure was adapted to enable negative prices on the Belpex DAM

To ensure transparency regarding volumes and prices of bids for control area balance, Elia publishes the following data: volume (i.e. regulating power) that can be activated up- and downward within 15'in order to compensate imbalances area and the marginal prices for activating these volumes, for all types of reserve.

- Others:
    - The Netherlands: Tennet (www.tennet.nl)
    - France: RTE (www.rte-france.com)
    - Germany: EnBW, TenneT, Amprion, 50 Hertz

2.1.2 Methodology: fixed price OTC equivalent

Since wind energy is variable, it is difficult to make an accurate estimate of its market value. The developed program allows such value assessment following a statistical approach. Wind power generators, for reasons of simplicity and risk reduction, are assumed to sell their electricity by means of OTC contracts to the electricity supplier. With this fixed price, 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 or changing market design.

The developed tool calculates the value of wind energy when traded on the power exchange.

By combining time series of energy generation and market prices taking into account inflation, and dividing the resulting income generated on the power exchange by the amount of energy generated, 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 taking 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 generated, when traded on the power exchange.

Concerning the time series of market prices, historical day-ahead and imbalance prices are respectively extracted from Belpex DAM and Elia System Operator. Due to the unavailability of adequate data, intraday prices are represented by Belpex DAM 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[2]. 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.[3]

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

$$\boldsymbol{Value} = \frac{\boldsymbol{P_{pred} * p_e + P_{pos} * p_{pos} - P_{neg} * p_{neg}}}{\boldsymbol{P_{prod}}}$$

With:

- value = fixed price that should be paid in the OTC market to equal the revenues that can be reached on the power exchange;

[2] Due to the availability of historical data of wind generation measurements and predictions, it is opted to use this data instead of the synthetic time series model developed in Task 2. However, this model remains useful to perform analyses in cases where the necessary data is missing.
[3] 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 feedback of results to the prediction model is feasible and 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.

- P_{pred} = wind power prediction as nominated the day before delivery;
- p_e = day-ahead market price settled the day before delivery;
- P_{pos} = prediction error when real generation is higher than predicted;
- p_{pos} = positive imbalance price,i.e. the price paid for the extra energy generated when the real generation is higher than the nomination;
- P_{neg} = prediction error when real generation is smaller than predicted;
- p_{neg} = negative imbalance price, i.e. price that has to be paid to buy the difference in energy when the real generation is smaller than the nomination;
- P_{prod} = total energy generated over the observed period.

When real wind power generation 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, this imbalance is with the imbalance charged by the TSO tariffs. 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 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 reduces the market 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 possible with better forecasts or with other measures to reduce imbalance. Figure 5 shows a graphical example of the imbalance loss over time due to imperfect wind power predictions.

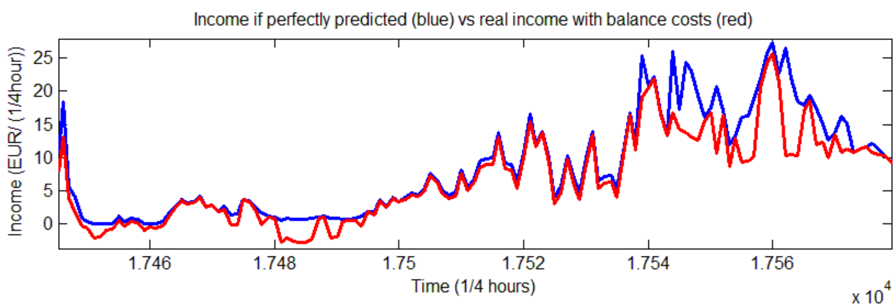


Figure 5: Income if perfectly predicted (blue) versus income with imbalance loss (red) (data 3E)

2.1.3 Results

2.1.3.1 Market value wind energy 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 park (regional). These configurations have a different value because of economies of scale: the larger the area involved, the more accurate the aggregated wind power predictions. It is important to note that the effects of wind energy on market prices are not taken into account in this study. This assumption is a good approximation when the contribution of wind power compared to the total generation is limited. However, for regions with significant relative contribution of wind energy, this effect should be integrated in the model in order to achieve more accurate results. A good example of this is Germany with its significant capacity of wind energy (Sensfus et al., 2008). In the future with larger capacities of wind power, this effect will become important.

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 based on input data until 2008. Since the electricity prices in this period were rising fastly and do not show the effects of the global economic crisis, results for 2009 are overestimated. The results are thus best compared in a relative manner.

A. 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.

B. 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 %.

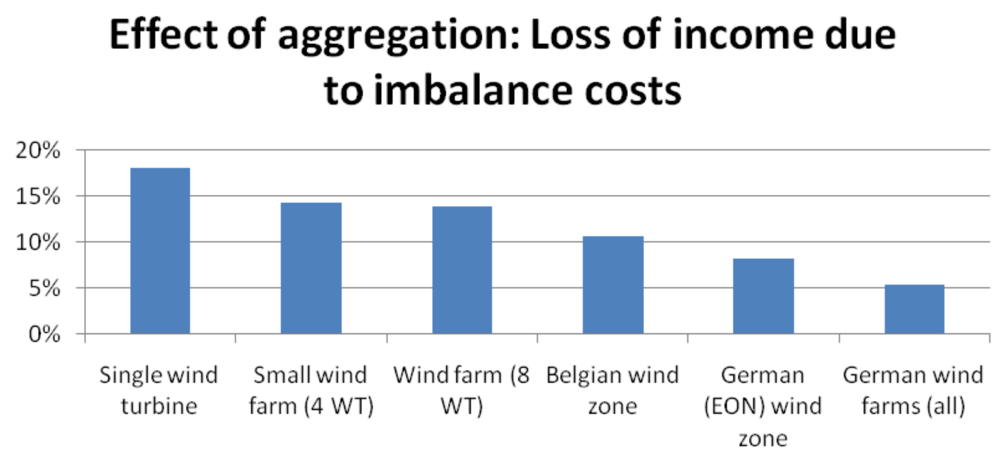
C. Larger wind region

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 prediction error is reduced significantly: the RMSE is about 11 % and the income loss is reduced to about 10.6 %.

To analyse a larger geographical spread, wind generation and prediction data of the four German control zones is used. The normalised 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 analysing an even larger spread. The reduced predictability 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 would be about 76.7 €/MWh.

The results are summarised in the figure below, 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, commissioned by Greenpeace (Woyte et al., 2008). 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.



D. Long term: 10 year

A tool for the generation of synthetic market results is 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 DAM prices of 2007 until mid-2008 and input series of wind energy generation 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 used for a statistical value assessment[4].

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 generated 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 €.

2.1.3.2 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.

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.

A. Value with perfect predictions or perfect intraday market trade

Firstly, for reasons of comparison, it is important to look at the direct market value of the generated 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.

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[4] Values of 2008-2009 were used as input for the synthetic time series generation of electricity prices. Since the majority of the price input data date from before the economic crisis, the results may be higher than expected based on today’s prices.

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.

B. 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 generation, 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 %.

C. 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 generation.

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%.

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

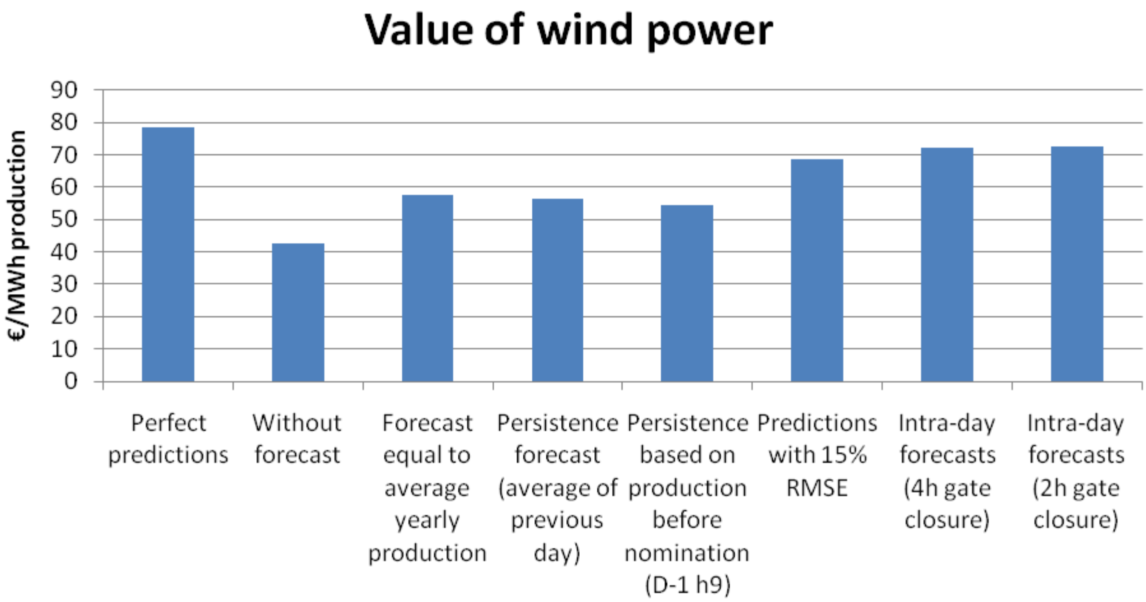
Results for state-of-the-art forecasts have already been given above. For easy comparison, the data for an 8MW wind farm are recalled here: The fixed price OTC equivalent of wind energy with state-of-the-art day-ahead forecasts is 68.6 €/MWh, while the RMSE of the predictions is 15.5 % and the imbalance loss is 14 %.

E. Value of wind energy with intraday 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 generation by means of trade. With such a market in place, it is generally interesting to continually update the nominations made day-ahead with intraday wind predictions, improving the value of wind power. As mentioned above, due to a lack of data, the assumption is made that the intra-day prices are equal to the day-ahead market prices.

Intraday 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 (TradeWind, 2009).

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%.



2.1.4 Conclusions

The market simulator is designed to calculate the value of wind energy when traded on the power exchange. The average value of wind power can be determined and is called the "Fixed Price OTC Equivalent" as this value can be compared to the fixed price negotiated in over-the-counter (OTC) contracts.

The simulator is a valuable tool for different stakeholders of wind energy. First of all, it is a valuable support for generator and supplier when negotiating OTC-contracts. Second, it can be an important tool for wind farm developers when planning investments. Different parameters can be evaluated on the total value of wind: location, portfolio, prediction tool, etc. Finally, this tool can be used by policy makers to evaluate the impact of different market design parameters on the profitability of wind: balancing responsibility, production support, etc.

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.

2.2 Phase 2: technical upper limit for wind power in Belgium

The Belgian electricity generation system is modelled and examined in terms of technical boundaries for massive wind development scenarios. Section 2.2.1 deals with the constraints when studying the aggregated wind power potential in Belgium. A UC-ED model is used to evaluate these scenarios without taking into account network constraints: 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 generation and the potential active demand-side management[5]. Section 2.2.2 drops the assumption that no grid constraints occur. A possible approach is identified to assess the necessary grid expansions and reinforcements to enable the connection of more wind.

[5] Task 5 also discusses the impact on costs and greenhouse gas emission. Results are not included in the final report but can be found in the Task 5 report.

2.2.1 Technical upper limit for wind in Belgium without network constraints

To consider the technical upper limits for wind power in Belgium, both a long and short term approach are adopted. On the long term, the technical limits are determined by the reliability of the Belgian electricity generation system and on how this system needs to be defined to successfully integrate large amounts of wind power. An electricity generation system has to be built so as to attain the desired level of reliability under a wide set of situations. Investments in the system might be necessary to cope with changes, such as the addition of wind power or an increase in demand. If the system is foreseen not to be sufficiently adequate, new investments in power plants can prove to be a solution. Therefore, the technical limits of wind power need to be seen in the context of maintaining reliability. With unchanged demand, addition of wind power would probably not lead to lower adequacy. However, in the light of increasing demand, an investment in a certain amount of wind power does not provide the same contribution to system reliability as a conventional power plant. This can also be considered as a technical limit for wind power in the Belgian system. The technical limits on the long term are not further covered in the final report but further information can be found in the Task 5 report.

On the short term, taking only the operation of the electricity generation system without its grid into consideration, wind power introduction is limited by the operation of the system. The composition of the Belgian system and the operational characteristics of the constituent power plants exert an important influence on the integration of wind power. Therefore, simulations of the Belgian system are performed with increasing installed wind power capacity.

2.2.1.1 Data

In a regular operation of the mentioned electricity generation systems, nuclear power plants operate in base load. With the chosen fuel prices, based on the International Energy Agency (IEA) World Outlook prices of 2005 (IEA, 2005), coal power plants come second after these nuclear plants in terms of fuel costs[6]. Gas-fired power plants, especially the efficient combined cycle power plants, are also used extensively due to their flexible operating characteristics. They 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 flexibility to the system.

[6] 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 less important 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.

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 on actual data from the Belgian Meteorological Institute (KMI) measured at a 10 m altitude and extrapolated to 80 m data applying the power law, (Peterson & Hennessey, 1978). The transformation from wind speed to wind power is based on the Vestas V80 wind turbine power curve (Vestas Product Information). The profiles that are applied in the UC-ED model, are depicted in Figure 6 and also used in (Luickx & D'haeseleer, 2007). They 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 here, 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 (Luickx et al. 2008), (Delarue et al., 2007). 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. They are shown in Figure 7 and are taken from actual 2006 demand data from Elia, the Belgian transmission system operator (TSO) (Elia, 2011). They are chosen as to represent distinct demand situations and have also been used in other studies .

2.2.1.2 Methodology

For the simulation of the Belgian system, a mixed integer linear programming (MILP) approach is used (Carrion & Arroyo, 2006; Delarue & D'haeseleer, 2007; Hobbs et al., 2001). The cases are modelled as optimization problems under cost minimisation. The model optimises the unknown variables such as activation level of power plants and generation quantities using this objective function. Typical non-convexities such as startup costs, minimum operating points and minimum up- and downtimes are taken into account. The problem is solved by the commercial MILP solver Cplex within the GAMS environment. A model simulating the operation of an electricity-generation system allows for an accurate reproduction of the elements that come into play, more specifically when integrating wind power in the system. The model takes all relevant operational characteristics of an electricity-generation system into account.

For this exercise, mainly the power plant characteristics, such as ramping rates, spinning reserves, the use of the pumped hydro storage stations and fuel usage are of importance.

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 two elements that define the variability of wind power, namely fluctuations and unpredictability, are examined in the simulations. Apart from meeting demand, the system is operated in a way that a certain amount of spinning reserves, which should amount to 1050 MW, is met.

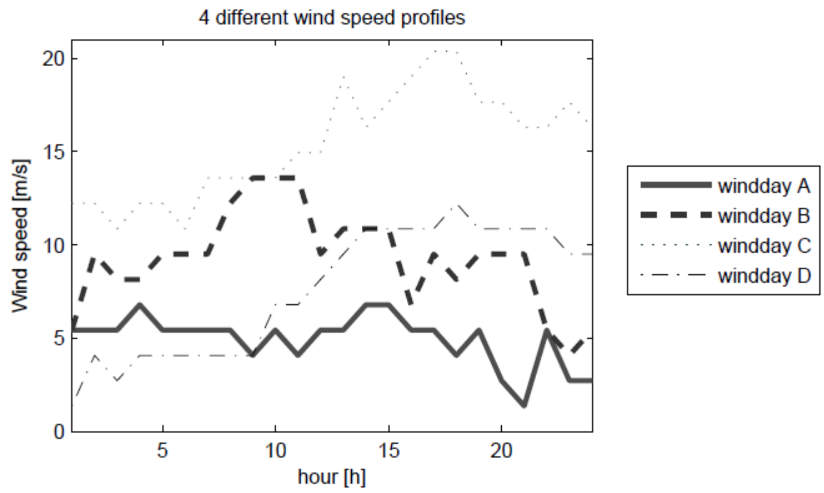


Figure 6: Wind speed profiles of 4 different days, showing typical fluctuations

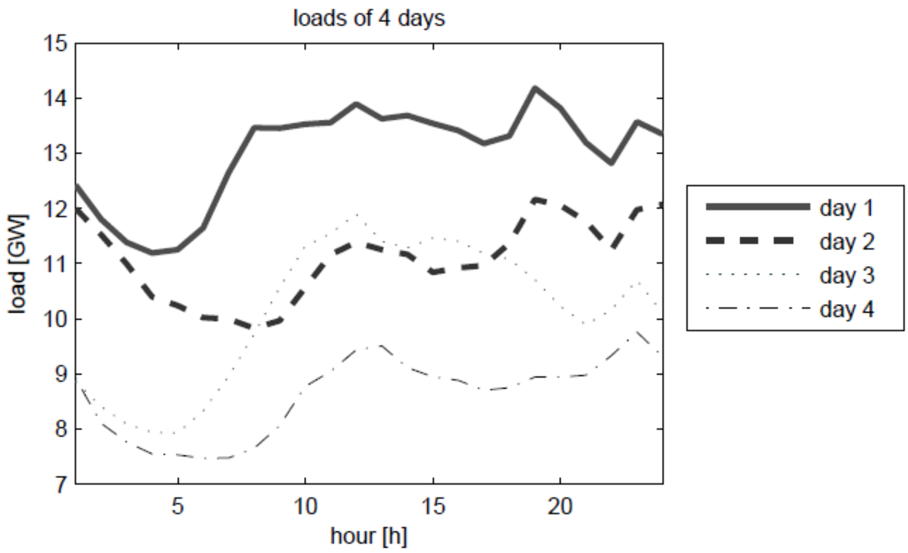


Figure 7: Demand profiles of 4 different days based on actual 2006 demand data of Elia

To evaluate the integration of wind power in Belgium, the demand and wind speed profiles of Figure 6 and Figure 7 are adopted for increasing amounts of wind power. In steps of 500 MW, wind power installations of up to 4500 MW are investigated. Two different points of view are considered in simulating the introduction of increasing amounts of wind power. First, a perfect forecast of wind speed is used. Secondly, a certain forecast error is applied to the wind speed. In this second analysis, the option of curtailing wind power is analysed as well. This is important to consider since at this stage, no export abroad at times of highly underestimated wind power forecasts is possible.

2.2.1.3 Results

A. 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 case of a seriously under-dimensioned electricity generation system the operation of the system will experience problems in the hour-by-hour operation of the system. As expected, no actual technical limits were incurred in the performed simulations.

B. 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. 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 ramping 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 activated during the UC phase and 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 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, 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 therefore 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 wind-days B and D lead to the largest technical barriers. The same exercise for a positive 1 m/s forecast error shows 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 Wind-day C. The reason is to be found in the shape of the power curve of the wind turbine. 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 Wind-day C, which has wind speed values around the rated wind speed of the turbine, experiences less difficulties in coping with the forecast error: 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 Wind-day 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 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, resulting in difficulties to balance demand and supply.

The ability of electricity generation systems to absorb the overproduction by 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 major share of power plants are already operating at partial load. The system then cannot always lower its output to such an extent that the extra wind energy can be taken in.

The reason for Wind-day 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. They 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 the power system 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 that curtailment becomes necessary. More wind that needs to be absorbed by the system leads to more potential problems. Another parameter which is even more important is the demand profile. Lower profiles have more difficulties integrating all of the generated wind energy.
It is not surprising that the largest curtailments occur for combinations of low overall demand with high levels of generated wind energy on the same moments as the demand is low. The combination of the four demand and wind speed profiles is represented in Table 2.

	Wind-day A	***Wind-day B***	***Wind-day C***	***Wind-day 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

Table 2: 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.

Using pumped hydro storage as balancing

Another possibility for the system integration of wind power is the use of pumped hydro storage. In Belgium, about 1100 MW of turbine power are available in the pumped hydro stations of Coo. These can be used both for peak shaving and for offering balancing services. An extensive analysis of this matter is discussed in (Luickx et al., 2008).

C. Belgium in a more European context

Several aspects of wind power should be seen in a more European context. Only looking at Belgium, disregards important opportunities for easier wind power integration. Three of them 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. When 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 coped with within the system itself. However, when combining two or more systems, the required spinning reserves for the same level of reliability will be lower than the sum of the individual 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. The formula of the sum of two standard deviations shows how the deviation of the sum is always smaller than the sum of the deviations:

$$\sigma_{system1+system2} = \sqrt{\sigma^2_{system1} + \sigma^2_{system2} - 2\rho_{system1,system2}\sigma_{system1}\sigma_{system2}}$$

$\sigma_{system1}$ = the standard deviation of system1

$\rho_{system1,system2}$ = the correlation between system1 and system2

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 interconnection between countries is the fact that the cheapest options for generation and for spinning reserves is used, disregarding the system of origin. The overall generation costs therefore decreases. 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 interconnection, disregarding grid limitations, Belgium fluctuations could also be managed by e.g. flexible hydro in the Alps or in Norway. The European dimension of the power grid thus reduces the costs of wind power integration. A more detailed analysis of how the cheapest generation units are used in a European context however falls outside the scope of this analysis. It has already been covered in literature, such as in (Delarue & D'haeseleer, 2007; Voorspools, 2004)

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 (KMI) and Dutch (KNMI) meteorological data and this for the years 2001 to 2006.

The frequency of occurrence of changes by a certain amount of MW for a one-hour interval is compared for three different situations. The analysis is performed for a rated 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 rated power and vice versa. When considering three sites in Belgium, still taking a 1 MW total rated 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 generating sites, 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 rated power. Taking even larger interconnected zones will lead to even less variable wind power generation.

2.2.2 Technical upper limit for wind in Belgium with network constraints

The assumption that no bottlenecks are present in the European grid is clearly a simplification of reality. Therefore, a methodology to add network constraints based on an AC load flow simulations is developed and presented in the specific task report. Due to the complexity of the suggested approach and some practical project constraints, it is however decided to work with a DC load flow model of the Belgian network in next project tasks. This model can be included transparently in the UC-ED model.

DC load flow is a simplified variant of a full AC load flow and is generally used for techno-economic studies. When using the right assumptions, the error on the active power flows through the transmission lines can be limited to 5%. Exceptional errors on individual lines may however still occur (Purchala et al., 2005). The main advantage of this technique is that a DC power flow is a linear problem avoiding the process of iteration, and thus reducing the simulation time significantly.

2.3 Phase 3: wind power in a liberalised market

The focus of the final phase of the project is to assess the ability of the power system to cope with variability of wind power. In a first part, available technologies with balancing capabilities are presented and discussed towards technical and economic parameters: large hydro storage, dynamically controlled gas fired power plant, energy storage technologies, demand-side response.

The second part deals with available and possible market mechanisms to acquire balancing services in an unbundled market. Belgian market mechanisms allowing to balance expected power deviations after gate closure are researched and benchmarked with other European countries (The Netherlands, Germany, Spain). Special attention is given towards the importance of balancing responsibility for variable RES-E in the framework of the tolerance margin for offshore wind power imbalances in Belgium.

In a final part, system simulations based on UC-ED with DC load flow are performed integrating 4320 MW of wind in the Belgian power system in 2020. Power system barriers and measures are discussed together with the impact of balancing technologies on operational efficiency and security of supply.

2.3.1 Technologies for balancing non-nominated power variations

Results concerning this section are discussed in detail in the Task specific reports to be found on the project website:

- Large Hydro Storage & Dynamically controlled gas-fired power plants
- Energy Storage technologies
- Demand-Side Response

Large hydro storage

A water dam as large hydro storage facility is, given enough water supply, probably the best way to enable more wind power in an electrical power system. With a water dam, variations in output of 100% are possible in one minute, no fuel costs have to be paid and no GHG are emitted (except for perhaps some biological processes). In Belgium however, no such facility can be installed. If we want to use this resource, we have to contract it in some way from other countries. Pumped storage can be a solution to this problem. A pumped storage facility enables both peak shaving and backup. It has the same advantages as a water dam, and reaches efficiencies between 70% and 85%. Furthermore, they do not have any problems with dry periods. The pumping mechanism however comes at a cost, because one has to pay for the use of electricity.

Dynamically controlled gas-fired power plants

Also a CCGT or a real peak power plant, e.g. open cycle gas turbine, can be useful for the implementation of wind power into an electrical power system. With a CCGT plant, the main advantages are found in the high flexibility, easy start-up and shut down process and the high efficiency, situated between 50% and 60%. Real peak power plants on the other hand can start up very easily, but their efficiency is lower between 20% and 40%.

Energy storage technologies

There is a consensus within the electricity sector that electricity storage has the potential to play a key role for improving the manageability, controllability, predictability and flexibility of the European power system. Energy storage technologies provide the means for a wide spectrum of power system applications. These may benefit generation utilities, transmission and distribution system operators and end-users.

Storage technologies will particularly play a key role in supporting the integration of significant additional capacities of wind energy sources. On one hand, a dedicated energy storage device combined with a wind plant can shape wind power output, transforming the wind generation into a firm and predictable energy source, hence enabling wind generation to better exploit power market opportunities. On the other hand, energy storage systems, which have prompt response and limited deployment times, offer additional measures of providing frequency control reserve to mitigate load-generation imbalances.

There is a quite wide range of electricity storage technologies available today or under development. In this report, an overview of the basic principles and of the main technical characteristics of various storage technologies (power rating, typical discharge times, investment and operation costs, efficiency, response time and life time) is presented. Results are derived from reviewing several papers. Due to the lack of maturity of storage technologies and due to the fact that these technologies are not yet widely commercialised, the papers reviewed often disagree on the values of these technical characteristics. Consequently, the accessible domain of values provided in this report for each characteristic is sometimes very large and must be used cautiously.

The suitability of each storage technology for a specific application depends on the characteristics of a technology. Some of them are intended for high power ratings with a relatively small energy content making them suitable for power quality, UPS or primary frequency control.

Others are designed for large or medium scale energy management, making them suitable for decoupling the timing of generation and consumption of electrical energy. However, the economic viability of a storage technology has also to be assessed according to investment and foreseen operation costs, market conditions and strategic objectives of the energy storage application. Several operational strategies can thus be considered for a storage unit dedicated to the mitigation of a wind farm variability. The choice of the most economical storage technology depends on this operational strategy as well as on the wind profile of the wind farm.

In this report, the storage technologies best suited and the more often recommended for supporting wind generation integration are identified. Four types of applications have been considered: provision of primary frequency control (Flywheels, Batteries), provision of spinning reserve, intra-day wind variability mitigation (Batteries and Flow batteries) and long term wind variability mitigation (Pumped hydroelectric storage and Compressed air energy storage).

Besides technical, several other issues arising from the deployment of storage systems as part of the electrical grid are a matter of debate:

- Various authors agree that widely distributed storage units, aggregated and operated as "multi-MW storage fleets", offer additional benefits (safety, reliability, competitiveness) over concentrated large units. On the contrary, some authors state that it is always cheaper to provide regulation to the control area rather than to compensate for the variability of individual wind plants directly.
- Value of immediate response time of storage systems should be recognised by market rules and regulation, as faster response time for supplying frequency control reserve can lead to reduced reserve requirements.

Demand-side response (DSR)

DSR offers a solution for imbalances in the intra-minute to intra-hour timeframe giving an alternative for power generation reserves. The total demand can be split up in permanently available base loads and loads liable to variations. Because the base load is permanently available, it can be delayed at any time. Moreover, with adequate technology, these loads can balance power immediately, giving an alternative for primary and for secondary reserve power. In that way, more time is given to tertiary, and economically viable, reserves to cover the imbalances. Although this measure solves a power deficit, at the end it does reduces the energy need.

In Belgium, a first calculation veils a potential of 358 MW available for DSR, only contracted from the most important domestic appliances (Table 3). This number is based on a minimal level of acceptance by consumers. DSR potential rises significantly, up to 946 MW, when all residential consumers participate in demand-side actions. Moreover, with the possible integration of hybrid and full electric vehicles, the annual household consumption may double which results in an important future potential, both for storage and DSR. The calculated potential is only an average power demand. In order to obtain the demand available at each moment, specific load profiles as described in the report have to be taken into account.

	Expected use [%]	Power [MW]
Refrigerator	5-10	23
Fridge	5-10	11
Electric water heating	50	117
Circulation pump	5	8
Electric heating	90	199
Total		**358**

Table 3: Estimated use of domestic appliances in DSR with the corresponding power

2.3.2 Market procurement of balancing services

Results concerning this section are discussed in detail in the appendices of the 2009 scientific report. These documents can be found on the website of the project.

- Balancing Management Mechanisms for Intermittent Power
- Tolerance margin for offshore wind generators

2.3.2.1 Balancing Management Mechanisms for Intermittent Power Sources

The accuracy of wind power output prediction tools increases with decreasing time horizons. In the imbalance settlement mechanism, BRPs submit their nominations based on predictions received day-ahead meaning at least 10 – 34h before real-time. For a single wind farm, the mean absolute error (MAE) of day-ahead predictions can amount up to 20% of the installed capacity. However, this error may drop to 5-7% when using predictions with a 1 to 2 hour time horizon (Milligan et al., 2009).

If BRPs could use predictions with shorter horizons, this could have a beneficial impact on the imbalance volumes. This may be an advantage for the wind power industry (less imbalance tariffs) and the TSO (less regulating reserves needed). Therefore, it is often defended by the wind industry that gate closure should be extended for wind power nominations.

An alternative for this demand is the development of intraday market mechanisms. In 2009, Elia started an Intraday Market which gives BRPs the possibility to adapt nominations intra-day. This request can be submitted as from 18h00 D-1 (also the time at which Elia approves or adapts day-ahead nominations according to congestion management measures) and at least 1h before real-time. For instance, to adapt nomination for 22h00, this request has to be sent before 21h00. However, Elia retains the right to decline or approve these adaptations in nominations but after acceptance, it cannot withdraw this right anymore without remuneration.

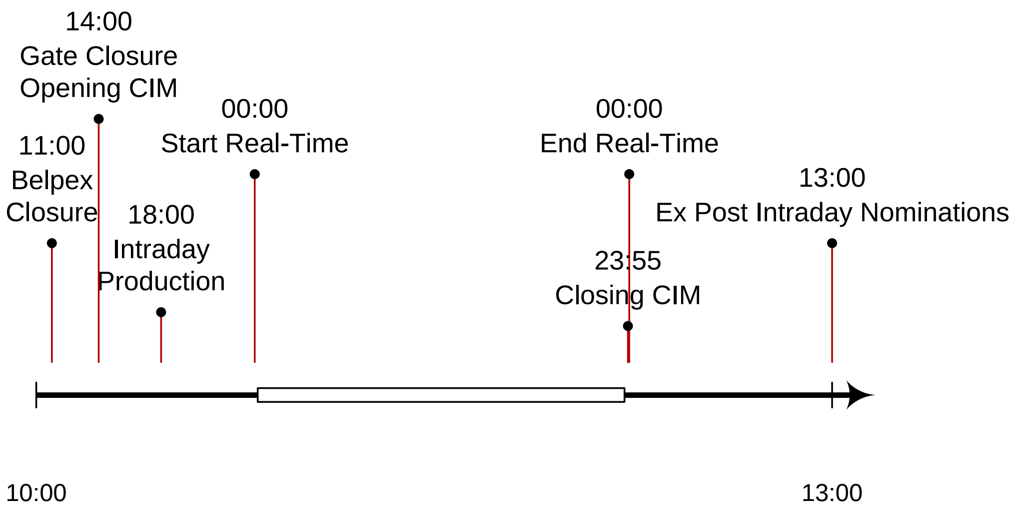


Figure 8: Chronological representation of balancing activities in Belgium for an arbitrary day

Portfolio management

As a first possibility to adapt positions after day-ahead gate closure, BRPs can manage their portfolio to intercept expected imbalances. To achieve this, they can use reserve power from flexible generation or customers in their portfolio to compensate for instance in case of lower or higher wind speeds. This is not always possible for smaller BRPs with limited generation capacity. As in Belgium most BRPs are relatively small in comparison to the incumbent, they face a competitive disadvantage concerning balancing possibilities. Additionally, balancing capacity needs to be flexible such as for instance certain hydropower or CCGT plants. However, the first is not extensively available in Belgium and the second is rather expensive. Today, wind turbines can also be used to manage the portfolio balance by new control technologies (Horns Rev offshore wind farm in Denmark) or the aggregation of geographically dispersed wind farms (which will not be applicable in a small country as Belgium).

A BRP can also use the spot market to reduce its imbalances by hedging its risk taking positions in the market. A BRP can buy for instance active power on the Belpex Day-Ahead Market (Belpex DAM) and tune its portfolio to this. If the wind is not blowing as expected, imbalances can be absorbed with the positions taken on the spot market. In contrast, if the wind resources are available, the BRP can reduce output of his most expensive generators. As the Belpex DAM closes 13 to 37 hours before real-time, possibilities are limited.

Intraday transactions

Besides portfolio management, BRPs can also maintain their balance after gate closure with intra-day transactions. It is for instance possible to execute bilateral exchanges with other BRPs after gate closure (starting after Day-ahead Energy Transfer Confirmation). The nomination for these internal energy transfers can be communicated to Elia until 13h00 the next day.

Also import and export with respect to the defined timing is allowed on the France-Belgium interconnection (Intra-day Allocation Mechanism). At 12 moments (gates) after gate closure, the participant can nominate import or export power within the limit of the allocated capacity, between France and Belgium at the given gate. Each gate takes place in different stages. This means for the first gate that the TSO publishes available capacity after which participants submit their request for capacity before allocation at gate closure (21h00). This is allocated by the TSO before 21h30. Then, participants can submit nominations before 22h00 that have to be confirmed before 22h45. Finally, the delivery period takes place between 0h00 and 24h00 and repeats itself 12 times.

To facilitate this market, an intra-day market on the power exchange Belpex has been opened (13 March 2008) where market participants are able to find positions or counterparties to trade after gate closure (from 14h00 and to 5′ before real time) and this for 24 blocks of 1h, or blocks of 4 or 6 h. As the minimal block is one hour and the imbalance settlement period is 15′, intra-day markets cannot be used to entirely cover imbalance variations inside the hour. Recently, Belgian and Dutch intraday markets are integrated through an implicit cross border capacity allocation mechanism for the Dutch-Belgian intraday capacity.

Imbalance Pooling

Complementary to previous mechanisms, BRPs can also pool their imbalances by signing a "Pooling Agreement". This means that Elia invoices the global netted imbalance to one of the BRPs in the pool.
This BRP distributes this total cost among the participants of the pool according to their individual imbalance. This technique should reduce the total imbalance volume due to counterbalancing of opposite imbalances of different BRPs. This mechanism is only financial and does not reduce the global system imbalance.
In practice, this technique is not often used. This can be explained by a confidentiality threshold in sharing imbalance information. Additionally, this tool is also not optimal in a situation where one player is much larger than the others. Imbalances of this player are difficult to neutralize, leading to disproportional benefits.

Reserve Market Bids

Another possibility is to sell reserves to Elia through the intra-day market. Under article 159, paragraph 2, of the technical code (Royal Decree 19.12.2002), generators with a capacity above 75 MW are obligated to keep their available capacity at the disposal of Elia at a price they fix when they submit nominations (14h00). They are activated by Elia in a merit order. With the Intra-day Production Mechanism, it becomes possible to adapt these prices intra-day (18h00).

2.3.2.2 Critical evaluation of tolerance margin for offshore imbalances

This section deals with an existing support mechanism to reduce imbalance costs for offshore wind power generators. This mechanism, allowing the generators to enjoy beneficial tariffs for imbalance volumes inside a 30% tolerance margin, is generally defended by a lower predictability of the offshore wind resources compared to onshore.

The objective of this section is to discuss implementation, motivation and financial impact of the tolerance margin as it is implemented in Belgium. Detailed information concerning context and implementation together with methodology and results of offshore predictability and impact on imbalance costs can be found in De Vos et al. (2011).

Predictability of offshore wind resources and production deviations

A preliminary study on predictability of power output originating from two offshore and three virtual onshore wind power plants is performed. Real measured and predicted wind speeds of 2004 are applied on a general power curve. The results confirm the higher unpredictability offshore with prediction errors (RMSE) being 2-6% higher for offshore locations (Table 4).

Under this argumentation, a particular Belgian regulation is installed allowing offshore wind power generators to enjoy beneficial imbalance settlement tariffs. This support is applicable on deviations (nominated – measured output) inside a tolerance margin of 30% of the nominated output. Although such support mechanism can be defended as it directly tackles the imbalance costs, this regulation is not transparent.

Table 4: Forecast error (MW) as percentage of the installed capacity based on day-ahead predictions (18h00 D-1)

[%]	DE RAAN	GOEREE	STAVENISSE	WOENSDRECHT	EINDHOVEN
NBIAS	-5,05	-5,53	1,41	1,11	2,75
NMAE	13,07	12,28	10,76	8,54	8,97
NRMSE	19,39	18,53	16,66	13,13	13,95
NMAX	79,26	89,00	78,96	66,32	80,39

Financial impact of the tolerance margin for offshore wind power production

The execution of the tolerance margin is studied for a virtual offshore wind power plant based on a general power curve and real measured and predicted wind speeds. The cost of the mechanism is determined by comparing the scenario with and without tolerance margin. Imbalances resulting from the generation deviations of a wind power plant are determined by subtracting the measured generation from the predicted (nominated) one. As in this study, only the impact of a wind power plant is researched and not aggregated with any other deviations in the BRP's portfolio, the total imbalance is assumed equal to the wind farm's generation deviation.

The financial impact of the support mechanism is calculated by attaching the applicable tariff (based on the electricity price) to the imbalance volume. When the reference prices of 2008 are used, this results (Table 5) in 5422 €/MW offshore installed which corresponds to a subsidy of 1.71 €/MWh generated offshore. If for a wind park of 2 GW, this subsidy is passed towards the consumer trough transmission tariffs this would results in a increase of the price of electricity with 0.12 €/MWh consumed. This subsidy increases with the electricity price, the frequency of wind park imbalances reinforcing the system imbalance, and the imbalance volume. When the same subsidy was calculated for a year with lower electricity prices (2009), it results in 4498 €/MW and 1.42 €/MWh respectively.

When intra-day markets are enabled to correct nominations according to new predictions received after gate closure, it is expected to reduce the imbalance volume, costs and the financial cost of the support. Calculations were made for a received prediction update at 19h00. This results in a maximal decrease of RMSE of 3%, leading to a 3.5% (2008) - 1.9% (2009) reduction in the support per generated MWh originating from the tolerance margin.

Table 5: Financial cash flows from TSO to the wind power producer caused by imbalance settlement for a wind farm of 100 MW (imbalance tariffs 2008)

€	SHORT	LONG	NET	€ /MWh
No 30%	2.752.341	3.500.652	-748.311	
30%	2.753.154	4.044.695	-1.291.542	
TOTAL			**542.231**	**1,71**

Offshore generation deviations and financial impact of tolerance margin calculated according to synthetic series of prediction errors.

In Task 3 of the WindBalance project, synthetic series of market and imbalance prices have been generated. The combination of these series with the synthetic series for offshore wind power generation and prediction gives an estimate of the economic benefit of the 30% rule for an offshore wind farm operator.

Analysis of the statistics of the generation deviations based on day-ahead and intra-day predictions are summarised in Table 6. The results for synthetic series of day ahead and intra-day predictions (Table 6 and Table 7) are:

- All generation deviations together add up to 26% of the generated energy. Of this figure, about 6.8% account for a positive deviation larger than 30% of the predicted power. About 3.5%for a negative deviation larger than 30% of the predicted power. This means that about 61% of the total wrong predicted energy (sum of absolute production deviations) is predicted in the 30% tolerance margin.
- During 46% of the time, the prediction error lies within the 30% tolerance margin. The energy generation during this period accounts for 63% of the total energy generation. These two percentages show that the prediction error lies most often in the tolerance margin when the predicted energy is highest (and thus when the tolerance margin is largest in absolute values).
- Table 7 summarises the results for the synthetic series of intra-day predictions. The shorter gate closure times obviously lead to better predictions.

The possible reduction in imbalance costs leads to an extra value for the offshore wind farm operator of the wind power on the day-ahead market. This amounts to about 4.5-5% extra ('grey' value, does not take into account support tariffs).

When intra-day predictions are used, the 30% rule adds extra value for the wind farm operator which amounts to about 3.8-4.3%. Although the prediction error is smaller and thus lies more often in the 30% margin, this extra value is relatively less than with day-ahead predictions. The reason for this is that the imbalance loss is already much smaller when using intra-day predictions.

Table 6: Statistics of the day-ahead prediction error for offshore wind energy

Relative deviation of production (ΔP_{rel})	Fraction of time	Ratio wrong predicted energy/ total production	Fraction of total energy in production deviations	Fraction of related total energy production
$\Delta P_{rel} < -30\%$	26.2 %	3.5 %	13 %	5 %
$\mid \Delta P_{rel} \mid \leq 30\%$	46.0 %	15.7 %	61 %	63 %
$\Delta P_{rel} > 30\%$	27.8 %	6.8 %	26 %	32 %

Table 7: Statistics of the intra-day prediction error for offshore wind energy

Relative deviation of production (ΔP_{rel})	Fraction of time	Ratio wrong predicted energy/ total production	Fraction of total energy in production deviations	Fraction of related total energy production
$\Delta P_{rel} < -30\%$	23 %	1.9 %	11 %	3 %
$\mid \Delta P_{rel} \mid \leq 30\%$	60,0 %	13.5 %	77 %	79 %
$\Delta P_{rel} > 30\%$	17 %	2.2 %	13 %	18 %

2.3.3 Balancing wind power in the Belgian power system

In this final task of the project, the system simulation model developed in Task 5 is used and adapted to assess the integration of 4320 MW of wind by 2020. This is the Belgian target for wind power put forward by the national action plan for renewable energy in order to comply with Directive 2009/28/EC (CONCERE-ENOVER, 2010). Even when taking into account current scheduled generation and network investments towards 2020, serious problems are expected to arise. The objective of this part of the study is to analyse integration bottlenecks step by step while adding and evaluating necessary measures. Additionally, the impact of flexible technologies as described in Task 7 are investigated with respect to generation adequacy (by means of the use of peak power plants and import) and operational efficiency (CO_2).

Section 2.3.3.1 deals with gathering main input data for system simulations of large wind power development scenarios. This input data is transformed into different scenarios dealing with installed wind power capacity, prediction error and demand. Additionally, different cases, representing relevant combinations of the balancing technologies described in Task 7 of the project, are presented.

Section 2.3.3.2 presents the system simulation model used to research the impact of wind in the Belgian power system while Section 2.3.3.3 discusses results. Finally, Section 2.3.3.4 puts forward conclusions and recommendations.

2.3.3.1 Scenarios and cases towards 2020

This section focuses on the way the main inputs for system simulations are modelled. In a first part, different wind power development projections towards 2020 are presented in terms of installed capacity. Secondly, wind power generation and prediction profiles are modelled: their variability and predictability are an important factor when assessing the impact on power systems. These profiles are combined with different demand profiles resulting in four scenarios. Finally, four cases are considered representing the integration of balancing technologies presented in Task 7.

A. Wind power development projections

Four projections for installed wind power capacity in Belgium towards 2020 have been provided in the framework of this study: national and offshore capacity is based on the literature while allocation over the different onshore regions (Figure 9) is based on the knowledge and experience. The four projections are presented in Table 8.

In November 2010, the Belgian national renewable energy action plan (NREAP) for renewable energy to comply with Directive 2009/28/EC was published (CONCERE-ENOVER, 2010). Due to limited resources, this task focuses entirely on NREAP-scenario putting forward a total installed capacity of 4320 MW by 2020, including 2000 MW offshore.

- Offshore
- West Flanders & East Flanders
- Limburg
- Antwerp & Flemish Brabant
- Namur & Walloon Brabant
- Liège & Luxemburg
- Hainaut

Figure 9: Map of Belgium representing the regions for available wind power data in different colors

Table 8: Projected installed capacity for Belgium in 2020

[MW]	W.Fl. + E.Fl.	Limburg	Antw. + Fl.Br.	Offshore	Namur + W.Br.	Hainaut	Liège + Lux.	Total
NREAP	**500**	**170**	**330**	**2000**	**400**	**520**	**400**	**4320**
Ambitious	750	250	500	2000	600	800	600	5500
Focus Offshore*	300	200	250	2825	300	400	300	4575
Focus Onshore	750	250	500	1000	600	800	600	4500

** The prediction from the European project REPAP2020 is developed with cooperation in the renewable energy sector federation Edora and ODE. For offshore wind they assume a capacity of 2824.6 MW in 2020. This would need a second offshore wind energy zone in the Belgian North Sea, which is not probable by 2020.*

B. Wind generation and prediction profiles

Wind generation profiles

In a first step, wind power generation profiles representing each region are shown in Figure 9. This contains three datasets representing hourly generation of one week capturing correlations between different regions. These time series are based on real data (wind farms, data from measurement masts and earth observation data) from each of the regions in focus during the same time period. Due to computational limits, only day three, four and five are included in the model while simulation results are only obtained for day four. Three generation profiles are provided:

- Stable generation profile: this scenario shows limited fluctuations.
- Lots of variations: this scenario shows frequent and large variations.
- Much wind generation at night: this shows high wind generation coinciding with low demand periods.

It was decided to focus only on the 'stable' and the 'lots of variations' profile. Both profiles can be seen as an aggregated wind power profile in Figure 10, and in their decomposed forms in Figure 11 and Figure 12. Note that the stable profile (Figure 11) shows a relatively high wind power output for all locations in Belgium.

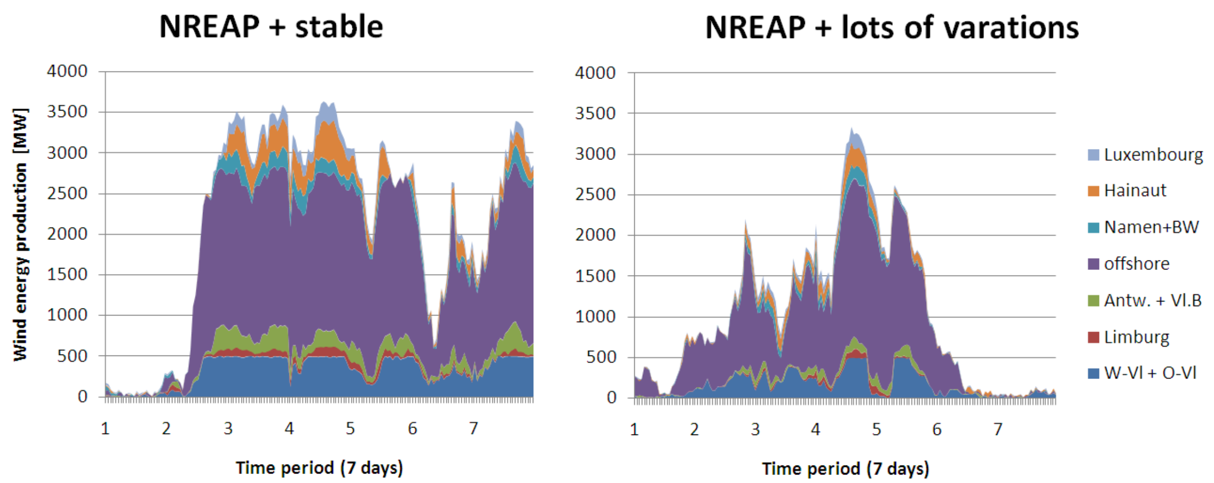


Figure 10: Generation profiles for the NREAP scenarios for a stable (left) profile and one with lots of variations (right)

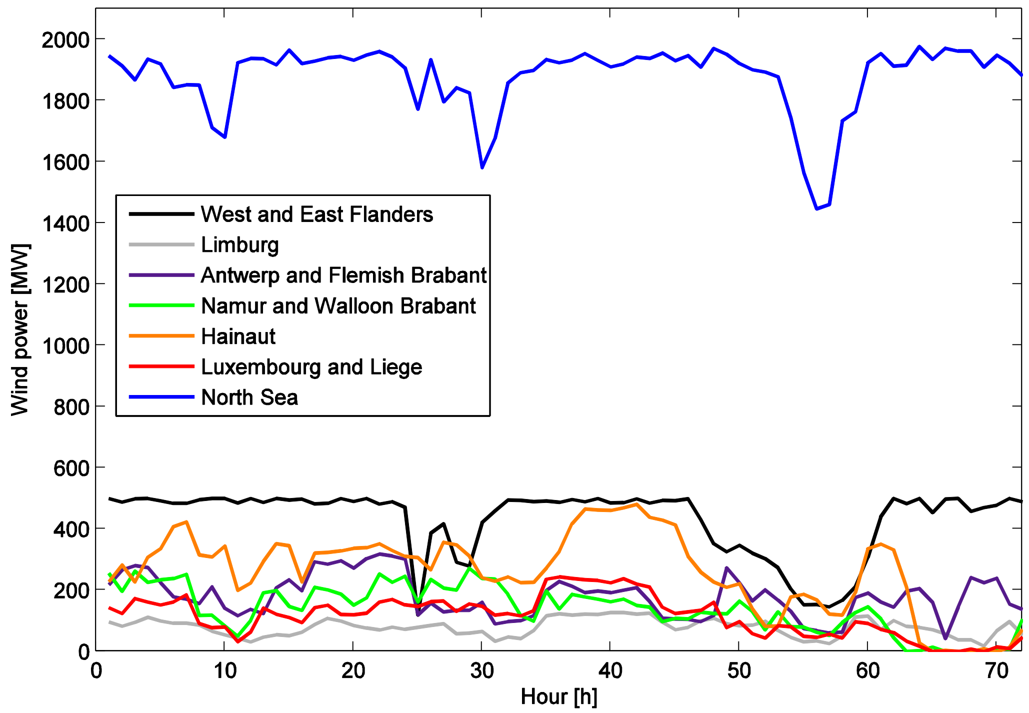


Figure 11: Wind profiles at different locations for the wind scenario with stable wind

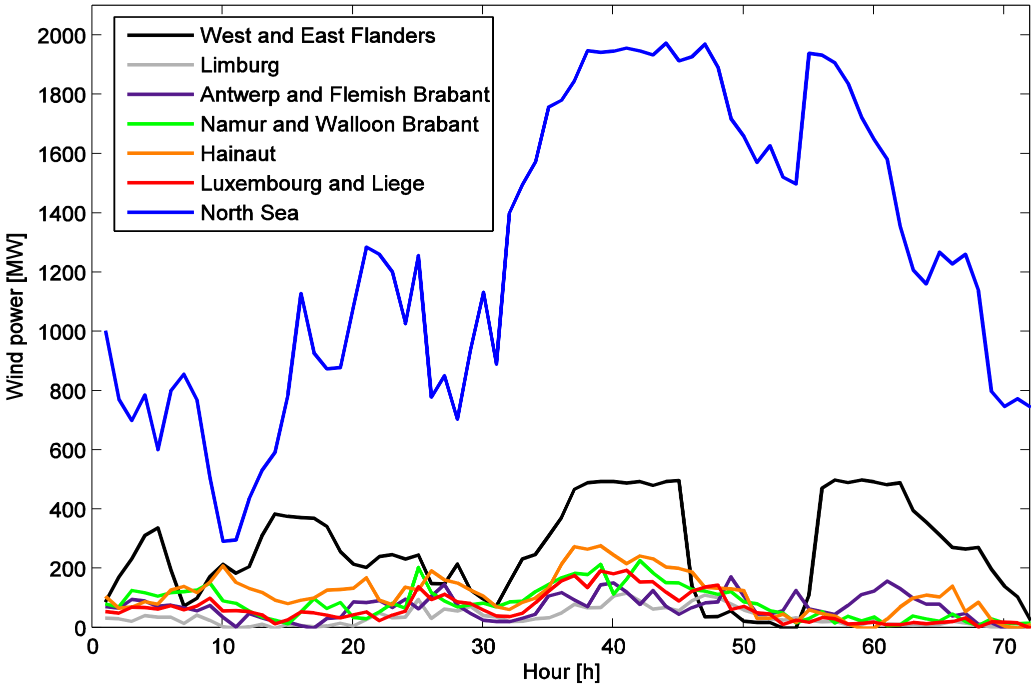


Figure 12: Wind profiles at different locations for the wind scenario with lots of variations

Wind generation predictions

In order to participate in the market, wind power is required to nominate positions day-ahead. Consequently, predictions are an important parameter when evaluating the impact of wind integration on power systems. As the actual prediction data were not available for the generation profiles in Flanders, synthetic prediction profiles have been built.

Two major requirements arise when modelling wind power predictions: firstly, prediction error for each individual location has to be modelled in a realistic way taking into account mean prediction error, variability and autocorrelation. Secondly, correlation of the prediction error over different regions is to be taken into account. These requirements are met with the approach presented schematically in Figure 13: wind speed prediction errors are extracted from an available database with historic wind speed measurements and predictions for different Dutch locations. They are processed to obtain time series of output prediction errors expressed as percentage of the installed capacity. Transposing these errors to the generation profiles of the different Belgian regions generates the required prediction profiles.

In a first step, the reference data are built: hourly measured wind speeds for five Dutch locations for 2004 (Figure 14) are obtained from the Royal Dutch Meteorological Institute (KNMI, 2009). These data are processed to represent wind speeds at hub height (100 m).

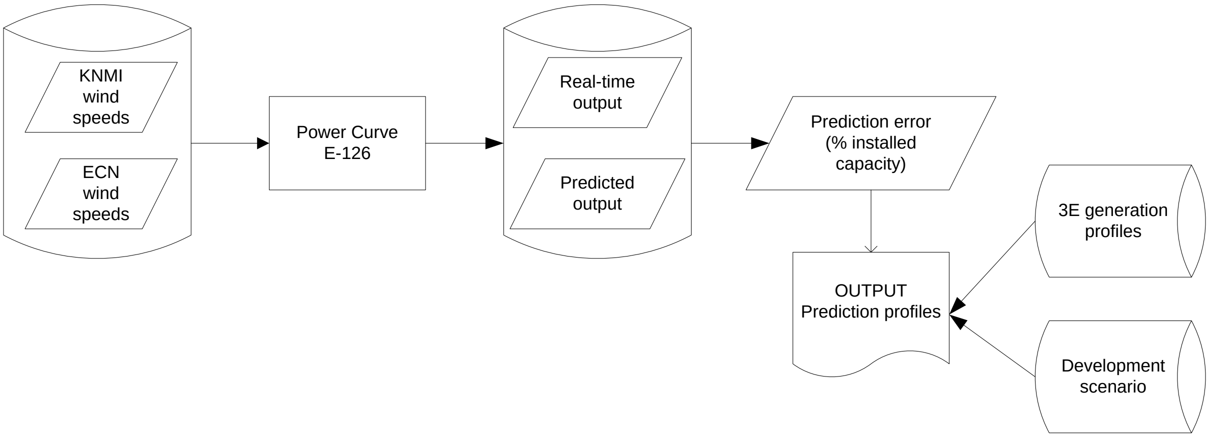


Figure 13: Modelling wind power predictions on generation profiles of 3E

Figure 14: Geographical representation of five measurement locations in the Netherlands.

Measured wind speeds are to be compared with the predicted ones in order to calculate the prediction error in m/s. Forecast data are acquired from the ECN (Energieonderzoek Centrum Nederland) used to perform day-ahead predictions (12 h day-ahead run for the next 72, 10’ resolution) (Brand and Kok, 2003). As the prediction tool is based on the inputs of the KNMI, these forecast data are compatible with the KNMI wind speed measurements discussed above.

As the objective of this part is to create generation profiles, wind speeds are to be converted into active power. A power curve is used which represents the output characteristics of a wind turbine, farm or park. In this study, normalised, regional aggregated power curves from the TradeWind project are utilised representing current technology (Mc Lean, 2008). These curves are more realistic for modelling wind parks as they take into account wind park effects (wake effects, electrical losses, unavailability, etc.). This results in smoother curves (not all turbines start generating power at the same time), lower active power output (aerodynamical and electrical losses, unavailability,...) and a smooth decrease in power output in case of high wind speeds (not all wind turbines shut down at the same time during a storm). (Figure 15) The wind speed data is transformed into active power output data by means of an interpolation over the power curve.

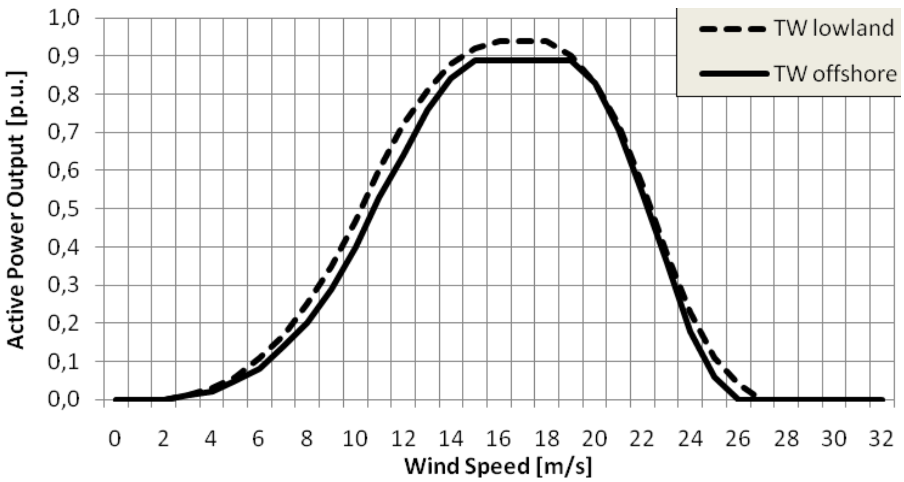


Figure 15: Regional, normalised power curves (source: Tradewind)

The prediction error for different locations is calculated by subtracting the measured from the predicted active power output[7]. A negative prediction error means that the wind speed was underestimated leading to a positive imbalance, a positive prediction error leads to negative one. Prediction errors are expressed in terms of installed capacity.

In the second step, the prediction errors are transposed to the generation profiles representing seven regions in Belgium: the relative prediction error is multiplied by the regional installed capacity presented in the wind power development scenarios and added to the real-time generation data. All five Dutch locations are transformed to seven Belgian regions as shown in Table 9.

[7] This methodology is the inverse of the definition provided by the TSO (Table 1, p.21)

Table 9: Allocation of Dutch prediction errors towards Belgian locations.

Belgian Region	**Geographical Classification**	**Reference Dutch Location**
West & East Flanders	Coastal	Stavenisse
Limburg	Inland	Eindhoven
Antwerp & Flemish Brabant	Inland/Coastal	Woensdrecht
Offshore	Offshore	Vlakte Van De Raan
Namur & Walloon Brabant	Inland	Eindhoven
Hainaut	Inland	Eindhoven
Liège & Luxemburg	Inland	Eindhoven

As the system model only takes into account profiles with a horizon of three days, it is difficult to select one representative prediction profile. Therefore, three days of prediction errors are randomly selected from the reference database. This process is repeated 40 times to generate 40 prediction profiles for each generation profile. In this way, representativeness of the results is comparatively assessed with the simulation time.

Resulting prediction profiles are assessed by means of three performance indicators. In the literature, three common error measures are (Madsen et al., 2004) used:

Average error over the evaluation period (BIAS)

$$BIAS = \frac{1}{N}\sum_{i=1}^{N}(X_{predicted,i} - X_{measured,i})$$

Mean Absolute Error (MAE)

$$MAE = \frac{1}{N}\sum_{i=1}^{N}| X_{predicted,i} - X_{measured,i} |$$

Root Mean Square Error (RMSE)

$$RMSE = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(X_{predicted,i} - X_{measured,i})^2}$$

Results for these indicators are shown in Table 10 showing acceptable results. As 40 predictions of three days (2880 entries) are compared to the full reference database (8784), this explains the deviation of predictions. Figure 16 illustrates the distribution of prediction error aggregated over the entire control zone. The similar shape of the curves show representative prediction errors.

Table 10: Performance Indicators for prediction errors compared between reference data (8784 hours) and generated profiles (72*40 hours) expressed as percentage of the installed capacity. (DR = De Raan, W = Woensdrecht, E = Eindhoven, S = Stavenisse).

	Data KNMI-ECN				Data BE			
	DR	W	E	S	DR	W	E	S
NBIAS	-5.11	1.54	3.20	1.54	-7.26	1.15	2.68	-2.80
NMAE	12.85	9.74	10.12	11.47	12.39	8.83	9.93	8.24
NRMSE	19.08	14.43	15.12	17.21	17.83	12.74	14.47	13.18
NMAX	83.09	82.01	81.11	85.84	57.23	61.72	66.16	60.84
NMIN	-89.00	-85.92	-69.70	-87.92	-69.37	-54.15	-60.79	-64.63

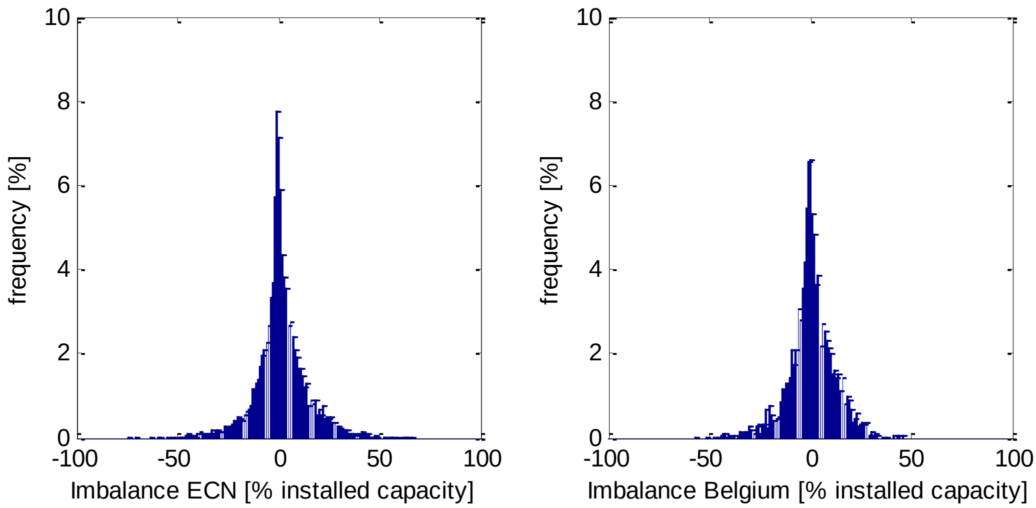


Figure 16: Histogram for aggregated prediction errors (expressed in percentage of installed capacity, [MW]) compared between reference data (8784 hours) and generated profiles (72*40 hours) for a scenario where wind is equally distributed over the locations.

In conclusion, this methodology puts forward a way to create synthetic prediction profiles for given generation profiles. This is useful when the actual prediction data are not available, which is often the case. The proposed methodology is characterised by a transparent approach and acceptable results. However, one drawback is observed: the size of the prediction errors depend on the position of the power curve which is not taken into account when transposing the prediction error to the generation profiles. In order to prevent predictions under zero or above the installed capacity, prediction errors have been truncated. For the stable profile, showing high wind generation, it results in lower absolute prediction errors.

A general drawback follows from the use of a limited number of profiles to perform simulations. This is however a common problem of system simulations which is explained by computational limits.

Consequently, the results strongly depend on the chosen profiles or scenarios. Concerning the predictions, the limited random sample survey (40 predictions) yields the worst cases not necessarily to be covered.

C. Demand Profiles

Two demand profiles are chosen:

- a high demand scenario which corresponds to a demand during the winter period;
- a low demand scenario corresponding to a demand during the summer period.

Both demand profiles are illustrated in Figure 17. The profiles are taken from actual 2008 demand data from Elia (2011) and are scaled up to the year 2020 based on annual growth rates of 1.6% for the period until 2015 and 1% for the period between 2015 and 2020 (De Jonghe et al., 2009).

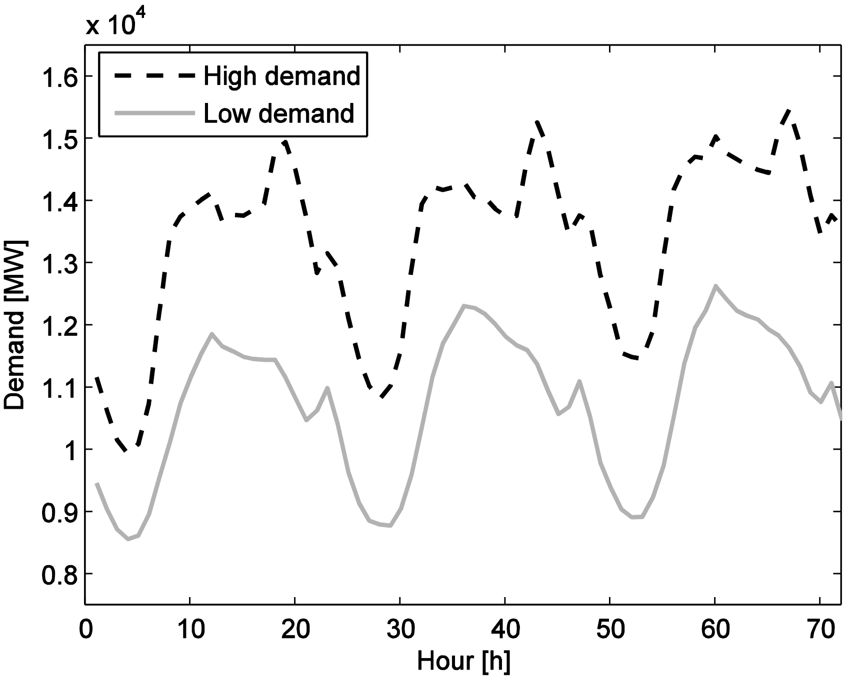


Figure 17: Expected high and low demand profile towards 2020.

D. Scenarios

Four scenarios are considered based on:

- Estimated installed wind power capacity in 2020 (NREAP): 4320 MW
- Two wind profiles: stable wind profile and profile with high fluctuations
- Two electricity load profiles: High and low demand

By subtracting each of the wind profiles from each of the demand profiles, a set of four scenarios is obtained[8] (Table 11). Consequently, wind is looked at as negative demand[9]. Notice that this subtraction entails that wind power has to be fully absorbed by the system, unless export (or wind power curtailment) is allowed in the model.

Table 11: Scenarios for system simulations

Scenario	Demand	Wind profile
Scenario 1	High Demand	Lots of variations
Scenario 2	High Demand	Stable
Scenario 3	Low Demand	Lots of variations
Scenario 4	Low Demand	Stable

E. Cases representing balancing technology combinations

In Task 7, different flexible technologies to balance wind power have been investigated. These technologies include:

- dynamically controlled gas-fired power plants (e.g. CCGT);
- decentralised storage;
- (pumped) hydro storage;
- demand-side response (DSR).

One of the objectives of this research task is to analyse the impact of these balancing technologies on the Belgian power system. The use of these technologies is expected to improve security of supply and operational efficiency. To analyse the impact, four cases are designed and simulated.

The reference case is the Belgian power system for 2020 integrating 4320 MW of installed wind capacity. The system model takes into account scheduled investments concerning generation and transmission. In a second case, additional CCGT-generation is reflected upon on top of the reference case. Due to constraints stemming from the model, impact of adding CCGT-capacity to the power system is zero. By consequence, no results will be shown in this case. Instead, reflections about adding extra CCGT will be given. In the third case, decentralised storage, characterised with a rated capacity of 150 MW and an energy reservoir of 300 MWh, is added on top of the reference case.

[8] with net load as seen by the remaining power system (i.e. without the wind turbines)
[9] This is in agreement with the merit order, since wind power has a marginal cost of almost zero.

In the final case (Table 1), 1000 MW of flexible capacity is added to the reference case by means of Demand-Side Response (DSR).

The four cases are designed to detect general trends when integrating the balancing technologies (additional pumped storage is not included due to the limited potential in Belgium) rather than to reflect realistic developments towards 2020. Decentralised storage is still a relative new technology while DSR is not yet implemented to a great amount in the Belgian system. This makes it difficult to estimate their potential for 2020. The potential for DSR is estimated by means of the results obtained in Task 7 for residential consumers: this is scaled with the entire demand in Belgium reaching a rough estimation of 1000 MW.

To summarise, four cases representing balancing technology capacities in the power system are defined (Table 12). A base case represents the power system towards 2020 including scheduled investments. Other cases add CCGT, 150 MW of decentralised storage and 1000 MW of DSR.

Table 12: Cases for system simulations

Scenario	Balancing Technology	Additional Capacity
Case 1	No (base case)	0
Case 2	CCGT	Not defined
Case 3	decentralised storage	150
Case 4	demand-side response	1000

2.3.3.2 Simulation model and approach

A. Simulation model and model setup

In order to investigate the impact of large-scale integration of wind power into the Belgian electrical power system, a Mixed Integer Linear Programming (MILP) model is used (Delarue, 2009). This model is an example of Unit Commitment - Economic Dispatch (UC-ED) model determining optimal activation levels of power plants in a power system over several time periods in order to meet demand at the lowest costs. UC-ED models are able to take into account all technical characteristics of the generation portfolio (ramping rate limitations, start-up time, reliability, etc.) and also all economic factors (fuel cost, CO_2 allowances, start-up costs, etc.). When necessary, they are able to take into account transmission system constraints by including DC-load flow simulations. Firstly, UC determines the on/off states of generators. Committed units start-up and run at a certain power level determined by the second step, ED.

This methodology for modelling power systems has already been introduced in Task 5 of the project in order to define the technical boundaries for wind power in the Belgian system.

In that task, the power system was evaluated as a copper plate, meaning that network constraints are disregarded. In this current task 8, this assumption is released and replaced by a DC load flow model. DC load flow is a simplified variant of a full AC load flow and is generally used for techno-economic studies. When using the right assumptions, the error on the active power flows through the transmission lines can be limited to 5%. Exceptional errors on individual lines may however still occur (Purchala et al., 2005). The main advantage of this technique is that a DC power flow is a linear problem avoiding the process of iteration, and thus reducing the simulation time significantly.

The model is designed to simulate a period of three consecutive days (72 h). Only results of the second day are taken into account in order to avoid the impact of starting and stopping errors. A distinction is made between the UC phase, where the power plants are scheduled for the period of 72 hours based on forecasted wind data, and the ED phase, where for every hour the active power plants are controlled based on actual wind power output. In both the UC and ED phases, the technical characteristics of the different power plants such as ramping constraints, start-up costs, minimum operating points and minimum up- and downtimes are taken into account.

As discussed in Section 3.1 a total of 4320 MW of wind power (installed capacity) is integrated in the model representing the Belgian power system in 2020. This capacity is allocated over the different network nodes according to the assumptions of 3E discussed in Section 3.1.1. The point of common coupling for each number of installed capacity is given in Table 13.

Table 13: Representation of installed wind power capacity together with their point of common coupling in the network model.

Region	Location (Node in network)	Installed capacity [MW]
West & East Flanders	Eeklo	166.67
	Izegem	166.67
	Rodenhuize	166.67
Limburg	Herderen	170
Antwerp & Flemish Brabant	Meerhout	110
	Lint	110
	Breugel	110
Namur & Walloon Brabant	Champion	200
	Achène	200
Hainaut	Courcelles	260
	Tergnée	260
Luxemburg & Liege	Heinsch	133.33

	Gramme	133.33
	Villeroux	133.33
North Sea	Zeebrugge	2000

In all cases and scenarios considered, a CO_2 tax of 30 €/ton CO_2 emitted is assumed. Fuel cost data is based on IEA, NEA and OECD (2010). The mutual relationship between the fuel cost together with the assumed CO_2 tax determine which power plants are going to be planned during UC.

In order to represent the power system in 2020, information concerning the current power system (generation park and transmission grid) together with the scheduled investments is taken into account as published on the website of Elia on August 2, 2010. Doel 1, 4 and Tihange 3 are therefore extended with 40 MW, 40 MW and 42 MW respectively, and 2275 MW of additional CCGT-generation together with 126 MW of additional gas generation is added[10]. Decommissioning of power plants is not taken into account as this data is not made available and difficult to estimate. However, it is to be stressed that the scheduled generation park taken into account corresponds with a highly positive scenario as the decommissioning of a number of power plants is to be expected (cfr. Kallo). Furthermore, the planned 2 x 3000 MVA reinforcement between Eeklo and Zeebrugge (STEVIN project) is taken into account and the line between Aubange and Moulaine is updated (Elia, 2010).

B. Simulation approach

Four net demand scenarios and four balancing-technology cases are simulated for their impact on wind power integration with focus on security of supply and operational efficiency. However, when integrating 4320 MW of wind in a simulation model based on the Belgian power system of today with the currently planned adaptations, different bottlenecks are detected. They render it impossible to run the simulations and assess impact of the different scenarios and cases.

In a first phase, different measures concerning network reinforcements and generation adequacy are applied to facilitate the proposed scenarios.

[10] The large coal power plant (E.On) mentioned on the Elia website (2nd of august 2010) is excluded from this study since it is expected that this power plant will not enter the stage.

In a second step, when the simulation model supports the integration of this amount of wind energy, the impact of different balancing technologies on security of supply and operational efficiency is investigated.

Simulation phase 1: base case

The integration of 4320 MW wind capacity in the Belgian power system towards 2020 is expected to face barriers. These barriers are noticed in the system simulation model when the model is not capable to give a proper solution. Specific measures are taken to overcome these simulation problems, representing possible solutions for reality.

In a first step, the grid boundary conditions are defined and remedies are proposed. As the focus of this study is not on grid specific bottlenecks, these remedies are not further evaluated. Moreover, because a DC power flow is used, deviations (albeit small) from real power flows may exist. Consequently, this approach does not allow the authors to define problem areas in detail. However, indications concerning possible problems and suggestions for solutions can be made.

Secondly, additional flexibility is to be added to the system to cope with low net demand scenarios. Therefore, compared to the standard model, nuclear power plants are allowed to run as load-following units, since load-following is expected to occur more frequently in the near future across Europe where where massive wind injection is expected. More specifically, the nuclear power plants are allowed to vary their output between 60% and 100% of their rated capacity in one hour (VGB PowerTech, 2010).

Finally, even with nuclear power plant modulation, spinning reserve power together with standing reserves[11] may be insufficient to cover for the overall system imbalances for the isolated Belgian system. To resolve this problem, import and export from and to France and the Netherlands are enabled with transmission capacities shown in Table 14. Values from Table 14, based on the Net Transfer Capacities (NTC) map of 2010, are published by ENTSO-E. Including import and export is relevant as progress is being made concerning the European internal market and balancing capacity may be available from other countries. Therefore, it is interesting to balance wind power on an international level.

[11] The model is designed in such a way that first spinning reserves, equal to the power plants operating in base load, and (if imbalances are to big) afterwards standing reserves, equal to the not yet scheduled peak power plants, are used in order to balance the system. If imbalance is still too high, import is used in a last instance.

However, the focus of this study is put on balancing wind power without relying on foreign balancing resources so as to detect the bottlenecks for such case. Therefore, the cost of import and export is kept artificially high to give incentives for balancing on the national level and assure security of supply on the long term.

Since 4320 MW of wind is brought into the Belgian power system and focus is on balancing wind power within the Belgian system, the imposed amount of spinning reserve capacity is increased in order to see the effect of adding additional balancing capacity in terms of spinning reserves. This increase in spinning reserve capacity is probably necessary when trying to balance wind power deviations as much as possible on national level. However, in current system settings, this increase in spinning reserve is not realistic.

Table 14: Net transfer capacities available at cross-border transmission lines

From (Country)	To (Country)	NTC
Belgium	The Netherlands	2300 MW
The Netherlands	Belgium	2200 MW
Belgium	France	1300 MW
France	Belgium	2900 MW

Simulation phase 2

The objective of phase 2 of the simulation is to investigate potential benefits of integrating the balancing technologies discussed in Task 7, by adding additional balancing capacity according to the cases described in 2.3.3.1, the impact on operational efficiency (CO_2 emissions) and security of supply (use of standing reserve capacity and import) will be examined.

This is investigated by applying each of the four proposed scenarios on the three cases with additional balancing capacity. Operational efficiency is based on CO_2-emission data of each fuel source used in the model, and is available from IEA (2005). Concerning security of supply, the use of both the standing reserve capacity and import is investigated. Increase in use reflects a lower security of supply and vice versa.

Table 15: Overloaded lines in the Belgian grid after installation of 4320 MW wind and the required capacity on each line in the system model to prevent overloading.

Percentage of overloaded hours for each scenario (in %)

Scenario	Line	1	2	3	4	5	6	7	8	9
1		9.69	39.27	0.63	36.67	0.63	0.63	51.56	69.38	4.79
2		3.44	57.92	2.29	52.5	1.35	2.29	64.48	95.31	6.67
3		0.94	3.02	0	79.79	0	0	20.73	82.71	0
4		0	1.04	0	97.08	0	0	31.25	97.71	0
Over all scenarios		3.52	25.31	0.73	66.51	0.49	0.73	42.01	86.28	2.86

Required capacity (in [MW])

Scenario	Line	1	2	3	4	5	6	7	8	9
1		815.2	1448.9	426.2	1849.9	414.5	459.7	838.2	565.8	517.3
2		648.4	1437.3	425.8	1999.7	415	459.2	858.8	560.2	529
3		632.9	1390.8	0	1612.4	0	0	629.5	486.6	0
4		0	1413.4	0	1525.2	0	0	684.9	480.2	0
	Maximum	815.2	1448.9	426.8	1999.7	415	459.7	858.8	565.8	529

Legend

Scenario	Case	Description	Line	Node 1	Node 2
1	High demand	Variations	1	Aubange	Heinsch
2	High demand	Stable	2	Avelgem	Zomergem
3	Low demand	Variations	3	Awirs	Rimière
4	Low demand	Stable	4	Jupille	Romsée
			5	Leval	Seraing
			6	Rimière	Seraing
			7	Lixhe	Lixhe
			8	Rimière	Rimière
			9	Moulaine	Aubange

2.3.3.3 Results

A. Simulation phase 1: results

Grid reinforcements

By means of DC power flow simulations, it is concluded that the power system today is not capable of introducing 4320 MW wind power without overloading certain transmission lines. The capacity constraints of a number of transmission lines are too stringent for the increased power flows stemming from the wind power generated. Table 15 shows the overloaded transmission lines in the Belgian power system.

As can be seen, most problems are situated in the South East of Belgium. In this area, the grid is less meshed.

The second problem is situated close to the coast. The 2000 MW installed capacity offshore wind power leads to an overloaded line between Avelgem and Zomergem. The most straightforward solution is to reinforce these lines. This solution enables further analysis but requires an additional evaluation by using full power flow simulations. This detailed analysis for further solutions is out of the scope and difficult to assess by using only DC power flow. The proposed reinforcements in the system model are done by adding parallel lines next to overloaded ones.

Regulation of nuclear power plants

After overcoming network constraints, simulation bottlenecks can be found in the generation system. It is concluded that there is not enough flexibility in the current generation mix to absorb high wind power output when demand is low. Therefore, this study suggests to attaining the additional flexibility from nuclear power plants by relying on their modulating output capabilities (as is done in France).

Currently, nuclear power plants in Belgium are operated in a base load mode, since there was no need for modulation. Initial assumptions do not allow any wind power curtailment or import/export. Under these assumptions, the model was not able to solve the specific case because the net demand profile was in some instances lower than the total installed nuclear capacity, which is equal to 5947 MW. The minimum of the low demand profile is 8570.9 MW and the maximum wind power output amounts to 4320 MW. Knowing that there are also Combined Heat Power plants (CHP) that must run during summer in industry (since these are industrial production profiles) with a maximum total output of 406 MW, a combination of those situations would lead to a problem situation.

A justified solution exists in allowing the nuclear power plants to operate in a load-following mode, an operation that will be more and more applied in the near future across Europe where massive wind injection is expected. More specifically, nuclear power plants can vary their power generation between 60% and 100% of their rated capacity in 10′ (VGB PowerTech, 2010) (hence leaving 0.6*5947 = 3568.2 MW). Since this model works on an hourly basis, the nuclear power plants are allowed to vary their output between 60% and 100% of their rated capacity in one hour (a conservative approximation since more load-following is technically possible; see Hundt et al. (2009)).

Only two demand scenarios of 72 h are looked at. This could influence the conclusions drawn about the nuclear part, since a demand lower than 8570.9 MW for the low demand scenario or lower than 9933 MW for the high demand scenario could occur during summer or winter respectively.

One way out would be to allow modulation up to 50%, which is feasible according to Hundt et al. (2009). However, alternatively, it is reasonable to keep the 60% modulation window and to assume that the operator should schedule the maintenance period of one unit during the expected period of weak demand in summer (holiday).

Yet, it has to be stressed again that in a first instance neither import or export are allowed, nor curtailment. In reality, import and export are available. However, as can already be seen from these simulations, curtailment and modulation will most likely be necessary in order to have a reliable system.

Import and export

After performing the grid extensions and modulating nuclear power regulation, the model still seems to end up with some problems, because the wind forecast errors are larger than the sum of the imposed (read also committed) spinning reserve capacity of 300 MW and the not yet committed standing reserve capacity, which can be at most 737 MW[12]. This capacity is high but in line with current reserves for the Belgian control zone[13]. A solution to this problem would be to increase the reserve capacity so that the largest forecast error can be balanced. This solution however is unrealistic and requires extra generation capacity to be installed, since imbalances larger than 3000 MW (and maybe even equal to 4320 MW) is possible. Therefore, import has been incorporated in the model against an artificially high price of using it, so that incentives are given to balance wind power deviations within the Belgian power system. In order to be correct, also export[14] is incorporated against a low price.

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[12] Spinning reserve capacity is defined as the sum of those parts of the committed power plants that is free to increase production, whereas standing reserve capacity is equal to the sum of the peak power plants (diesel power plants, turbojets, gas turbines) not yet committed.

[13] According to the TSO, reserves for 2010 were on average: 100 MW primary, 137 MW secondary and 661 MW tertiary reserves.

[14] Note that export in this context can to some extent also be seen as curtailment, since it is modelled as energy flowing out of the Belgian electrical power system. On the other hand, import can represent the required upward reserve capacity.

However, it is expected that this export will not be used since the regulating nuclear power plants, as described above, are capable to withstand the combination of minimum demand, maximum wind and maximum CHP power output.

Extra balancing capacity in terms of spinning reserve

In order to investigate the effect of increasing the amount of imposed spinning reserves, spinning reserve capacity is brought to 1055 MW, equal to the largest power plant (Tihange 3). Note that this capacity is significantly high compared with current reserves for the Belgian control zone. However, since 4320 MW of wind is brought into the Belgian system and focus is on balancing wind power within the Belgian system, such an increase would probably be necessary in order to lower the use of both standing reserve capacity and import.

Base case results concerning operational efficiency (CO_2 emissions)

After implementing all necessary adaptations to the Belgian electrical power system, the proposed set of four scenarios is simulated. Results of total CO_2 emissions are illustrated in Figure 18. Results are visualised as a distribution based on the 40 prediction profiles.

Firstly, it is noted that for scenarios 2 and 4 where a stable wind generation profile is used, the total CO_2 emissions are significantly lower compared to the scenarios including high wind variations. This is, however, in this case mostly due to much higher wind power output in the stable profile considered and is not so much a consequence of the stable versus highly fluctuating character. Wind replaces in these scenarios a part of the CO_2 emitting generation sources. Since the difference between the produced wind energy of the stable profile and the wind profile with lots of variations differs too much, no conclusions can be drawn on the effect of this difference of variability in CO_2 emissions. Secondly, the histograms clearly show that during periods of low demand (scenario 3 and 4), less CO_2 is emitted because less CO_2 emitting generations plants are used to meet demand.

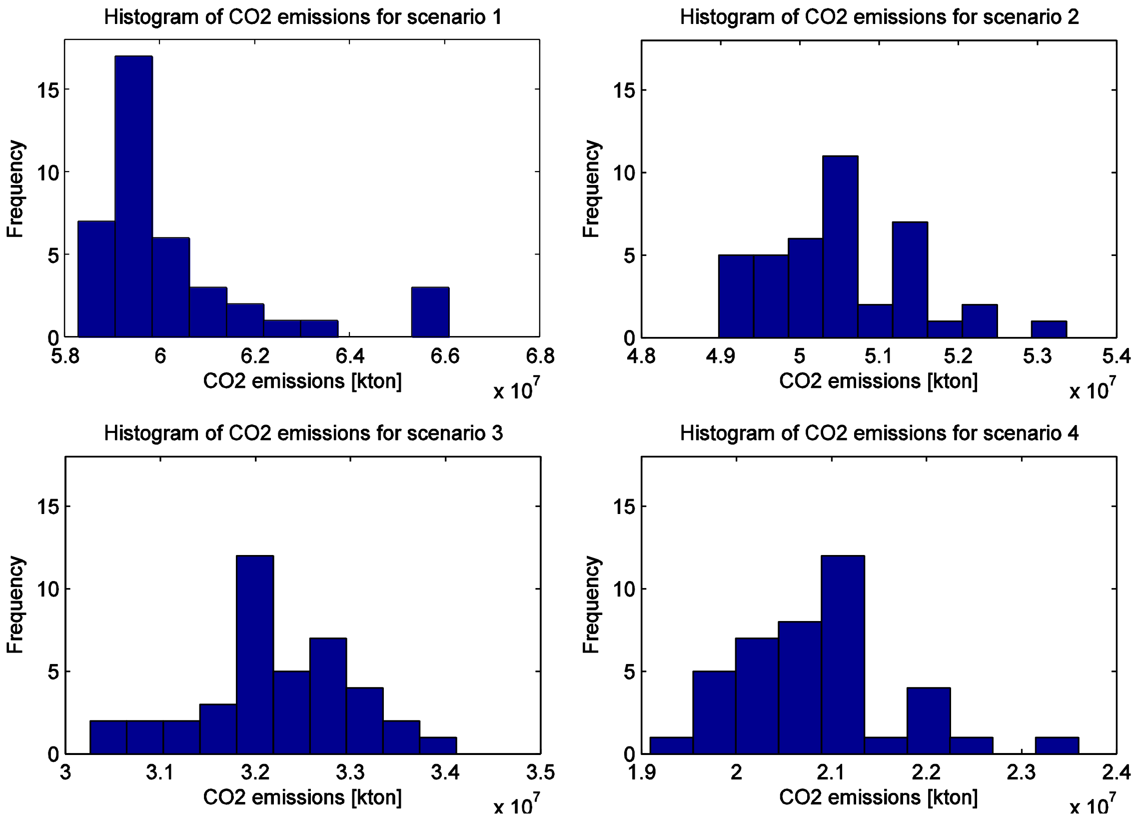

Figure 18: CO_2 emissions for all four cases after reinforcing the grid.

Figure 19 shows an example of the real-time (economic dispatch) nuclear power regulation for two simulations of the stable wind power profile combined with the high and low demand scenario respectively, while Figure 20 shows the histograms with the actual total nuclear power produced by all nuclear power plants for all simulations, split up per scenario. The full load observations, meaning all nuclear power plants producing at full power, have been left out. From Figure 19, all scenarios require regulation of nuclear power. In scenario 1, 2 and 3, however, this result stems for most from the sequential way of working of the MILP model when optimising for the ED phase. During the ED phase, the MILP model first seeks a minimal cost solution where the imposed spinning reserve capacity of 300 MW is demanded. If this imposed spinning reserve capacity cannot be obtained, due to a large forecast error, the model secondly searches for a solution in which the spinning reserve capacity, and thereby the reliability of the system, is maximised. However, due to this maximisation of spinning reserve capacity, the most cost optimal solution will probably not be obtained anymore, by which it is possible that nuclear power plants will not be scheduled to their full load. This results in more observations of modulating nuclear power plants. In a third and fourth instance, standing reserve capacity and import come at stage, respectively, if spinning reserve capacity is not sufficient to balance forecast errors.

Here, however, minimisation will be done again towards costs, giving a correct representation of the nuclear power produced during economic dispatch.

In scenario 4 (low demand and stable wind profile), nuclear regulation stems from two sources: on the one hand the optimisation procedure as described before, on the other hand the combination of a high wind power output (see Figure 11: high wind power output for the stable wind power profile) with low demand (during the night) as mentioned above. In case of scenario 4, a regulation bandwidth of 1105.3 MW is used.

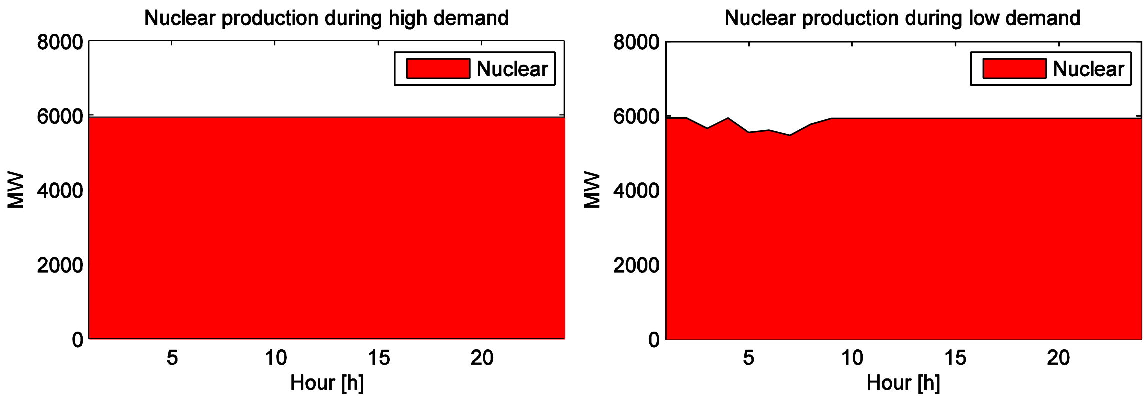

Figure 19: Nuclear power output for the two stable scenarios in which nuclear regulation is enabled.

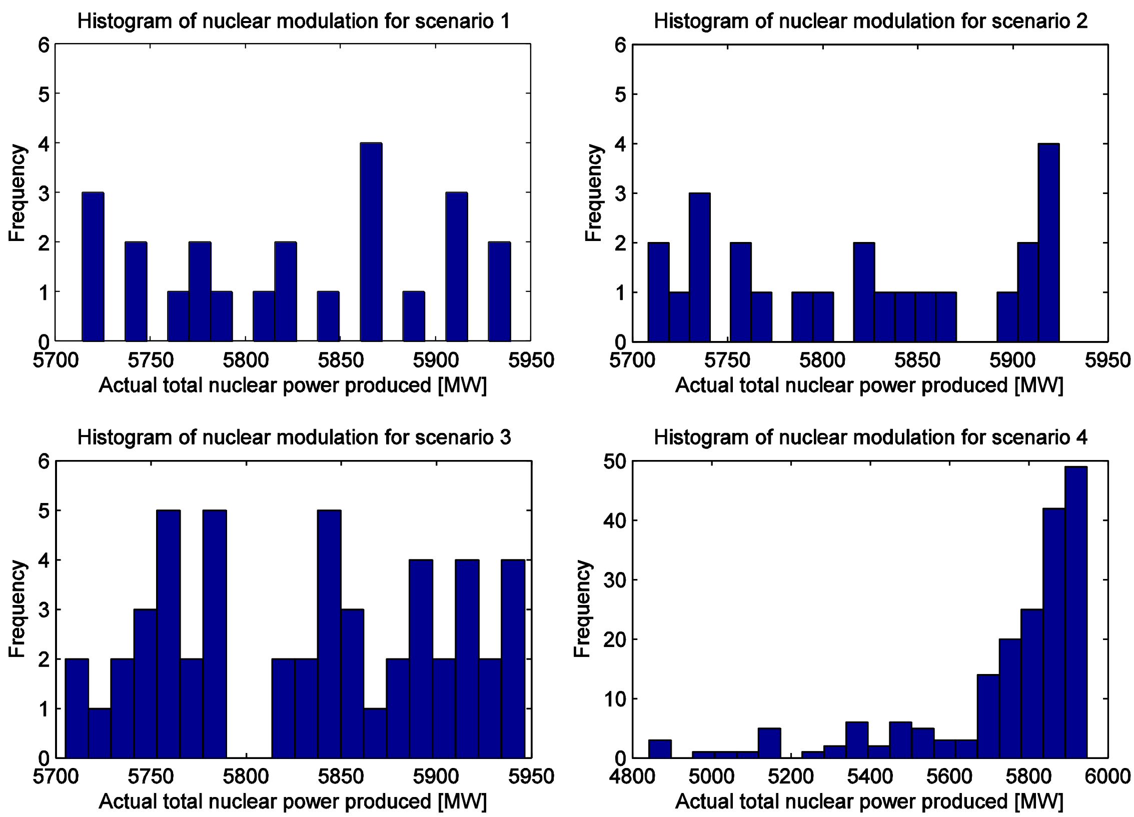

Figure 20: Frequency of actual total nuclear power production for all scenarios. Full load observations, meaning all nuclear power plants producing at full power, have been left out of the figure.

Because the reduced power shown in Figure 20 might also be the result from the planning schedule made during UC, a clarifying figure is added: Figure 21 illustrates the difference between the committed nuclear power during UC and the dispatched nuclear power during ED: the amount of nuclear power committed during UC is subtracted from the actual nuclear power produced during ED. In this way, the possibility and use of nuclear power to lower or increase their power output from what is previously scheduled during UC can be shown. Negative power implicates a lower actual nuclear power output, thus downward regulation, positive power implicates upward. As can be seen from the figure, upward regulation is a factor smaller than downward. This is due to the fact that during the unit commitment phase, the nuclear power plants are mostly scheduled close to full operating power, leaving less room for upward regulation, and more for downward regulation (an expected behaviour). Furthermore, the observations of scenario 1, 2 and 3 are for most due to the sequential way in which the model works when optimising for the ED phase (as mentioned before), thereby regulating nuclear power plants downward. In scenario 4, downward and upward regulation is stemming from both the way in which the model works and the balancing mechanism available from the nuclear power plants.

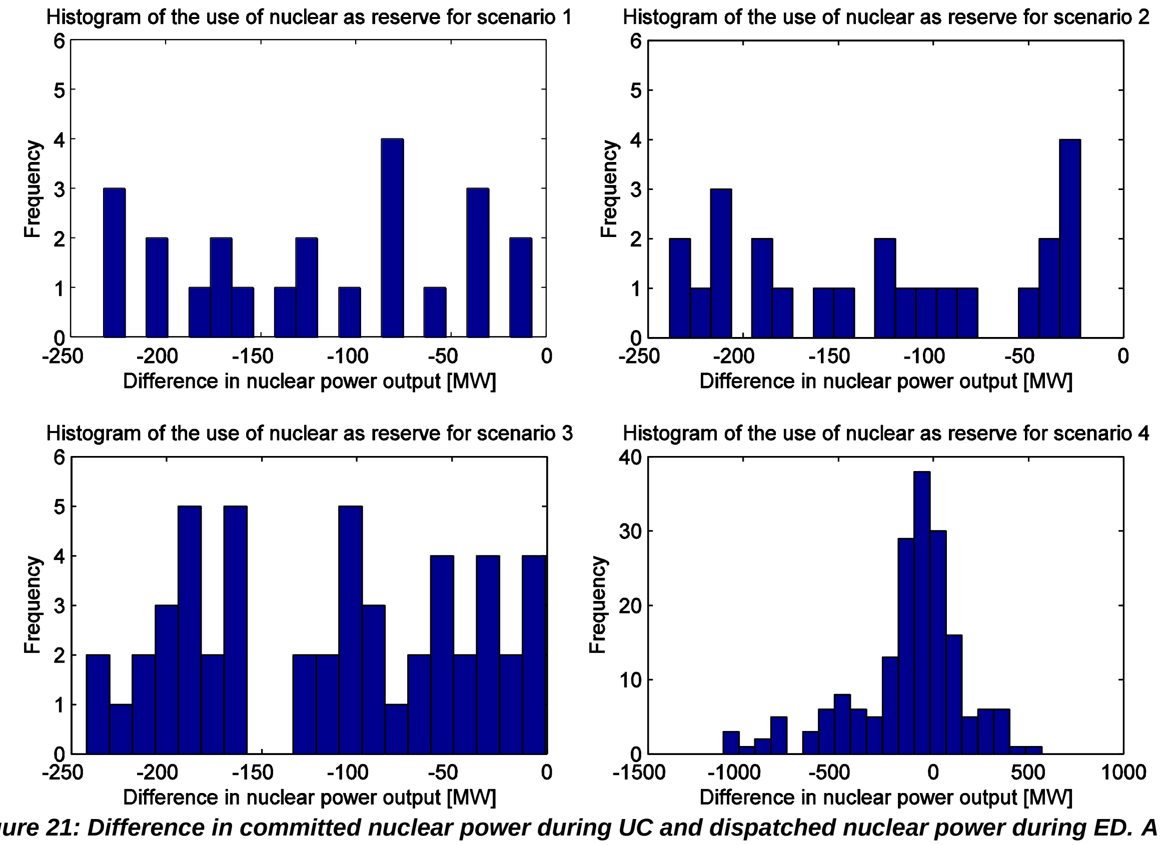

Figure 21: Difference in committed nuclear power during UC and dispatched nuclear power during ED. A negative power difference implicates downward regulation of nuclear power. A positive power difference implicates upward regulation of nuclear power.

Base case results concerning security of supply (use of standing reserve capacity and import)

In this report, security of supply is looked at from two viewpoints. First, this is from the use of the standing reserve capacity. A large use of this capacity means that spinning reserve capacity is fully in use in many situations, resulting in a less secure system. Secondly, the use of import from the neighbouring countries is investigated. A large use of import capacity shows that the Belgian system is not capable to integrate 4320 MW without relying on neighbouring countries, also resulting in a less secure Belgian system.

Figure 22 deals with the relative use of peak power plants (standing reserve capacity) for balancing purposes, meaning the power produced by peak power plants divided by the maximum amount of peak power available (equal to sum of the available power from the peak power plants not committed). This last parameter reaches maximally 737 MW. From the figure, it is clear that, in case 300 MW of spinning reserves are imposed, peak power plants are used regularly in all four scenarios. This can also clearly be seen from Figure 23 where the relative use of the standing reserves is plotted against the corresponding prediction error for wind power. From this figure, it is clear that the larger the prediction error, the larger the use of the standing reserve capacity in order to meet demand requirements.

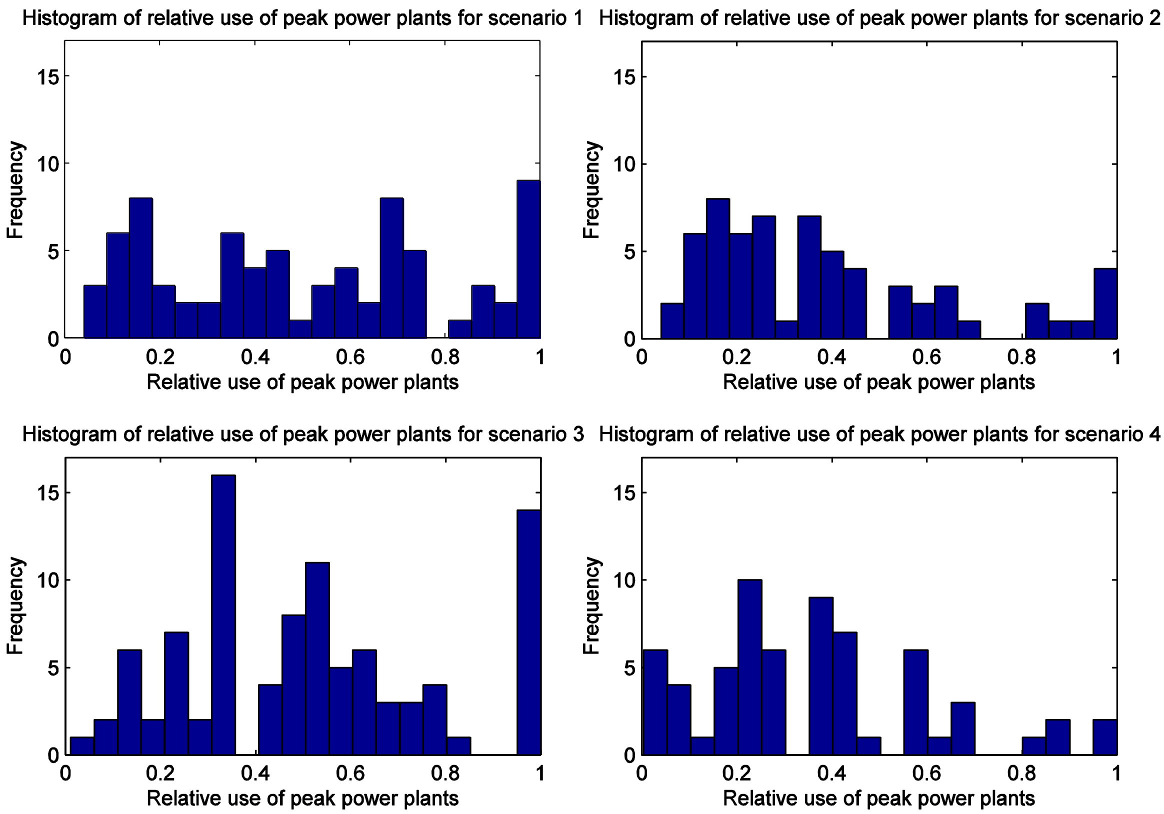

Figure 22 Frequency of the use of peak power plants.

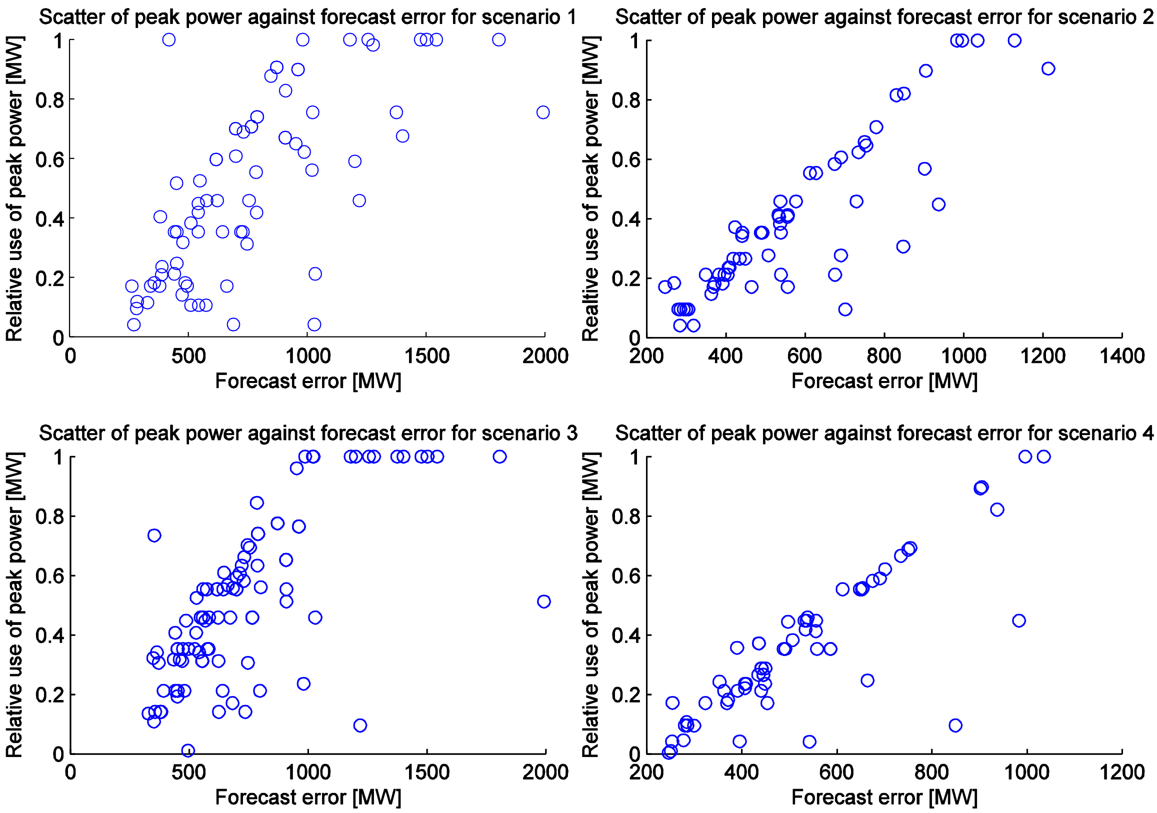

Figure 23 Relation between forecast error and peak power requirements.

Furthermore, three more or less remarkable results can be noticed from Figure 23. First of all, the scale of the x-axis in Figure 23 is smaller for a scenario with a stable wind profile (scenario 2 and 4) than for a wind profile with lot of variations (scenario 1 and 3). The reason for this is found in the truncation of the predictions as explained in Section 2.3.3.1. Since the stable wind power profile generates a large output and a wind turbine cannot generate more power than its installed capacity, large positive prediction errors have been truncated, resulting in lower absolute prediction errors. For this reason, a smaller x-axis is plotted for scenario 2 and 4, also resulting in less simulations, where standing reserve capacity is used in these scenarios.

Secondly, forecast errors smaller than 300 MW seems to require standing reserve capacity. This is due to the way in which the two hydro storage facilities in Coo are implemented in the model.

These pumped storage facilities can, in contrast to other power plants which can only change the level of their output, still decide to operate in turbine mode, pump up or keep the power output constant in each actual hour that is optimised in the economic dispatch phase, while they have to take into account the uncertain[15] future in the upcoming hours. In other words, when a certain actual dispatch hour is optimised, the pumped storage facilities decides on the most economic action to take, taking into account that the uncertain demand of the upcoming hours still has to be fulfilled. This can result in the fact that the pumped storage facilities decide to operate less in turbine mode or pump (more) water up during a dispatch hour in order to fulfil upcoming uncertain demand, thereby increasing demand and requiring standing reserve capacity when this fact coincides with a prediction error in the neighbourhood of the spinning reserve capacity.

Thirdly, Figure 23 shows that even when prediction errors are larger than the sum of the amount of spinning reserves (300 MW) and the maximal amount of standing reserve capacity (737 MW), standing reserves will not be fully occupied by the system. This result can be linked to two causes. On the one hand, as described before, the pumping units can change their behaviour during ED as opposed to how they were planned during UC. In this way, the model can decide to pump less, to pump nothing at all or to operate in turbine mode during ED in comparison with what was previously planned during UC. This leads to an 'extra' reserve capacity available in the system, stemming from the pumped storage facilities. On the other hand, the model is programmed in such a way that 300 MW of spinning reserves must be attained during UC.
However, nothing prevents the model of holding more than 300 MW spinning reserves when this is economically preferable, leading to an 'extra' spinning reserve capacity.

In Figure 24 four histograms are represented, corresponding to the four scenarios developed. As can be seen from the figure, each scenario requires import capacity in order to be able to fulfil the large imbalances originating from the large prediction errors for wind power. This can also clearly be seen from Figure 25 where the import quantity is plotted against the corresponding prediction error. From this figure, it is clear that the larger the prediction error, the more import is required in order to meet demand requirements. Moreover, only very large forecast errors require import capacity. Notice that in scenario 1, one simulation is shown, where import is required with a forecast error close to 420 MW.

[15] Uncertainty in this context refers to fact that the actual wind power outputs of the upcoming hours are still unknown. So for the upcoming hours, the synthetic prediction profiles are used.

This result can again be subscribed to the way in which the two pumped hydro storage facilities are implemented in the model. From Figure 24, it can further be seen that in the scenarios where a stable wind power profile is used, less import is required. This is due to the truncation of the predictions as explained in Section 2.3.3.1.

Note that no figure for export is added to the results, because export is not used in the four scenarios considered. This confirms the expectations made above: the regulating nuclear power plants are capable to withstand the combination of minimum demand and maximum wind and CHP power output.

The differences between the scenarios described in this report are mostly due to the specific input data used. However, these results will still play a significant role in justifying trends when extra flexibility is introduced into the system. Nevertheless, the conclusions made about the grid reinforcements, the regulation of nuclear power plants and the import and export capacity remain very effective.

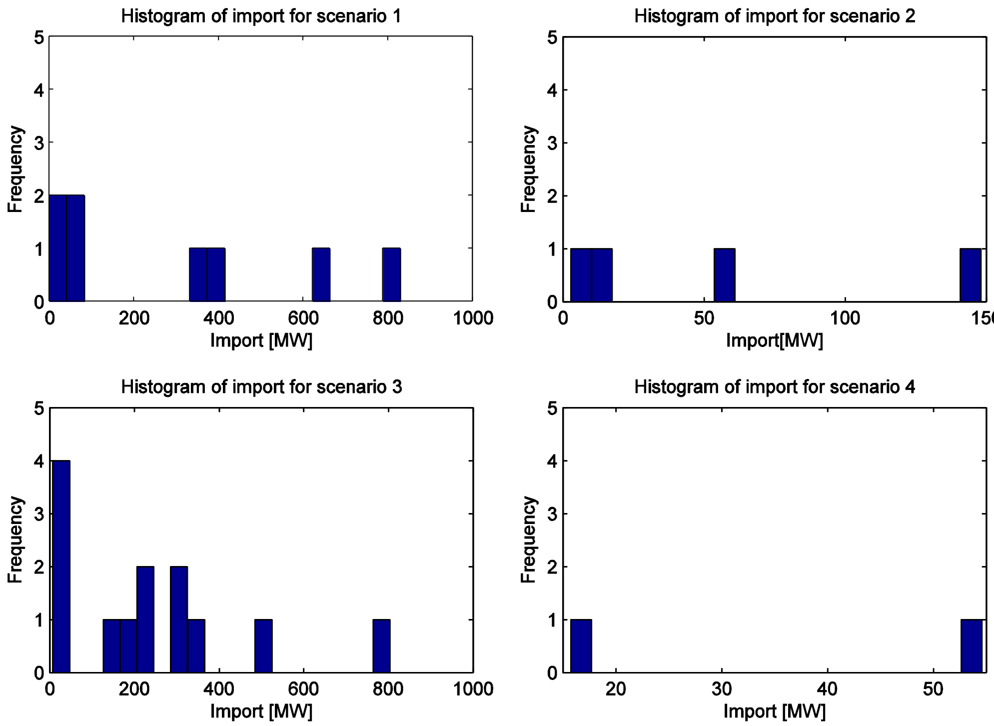

Figure 24: Frequency of import power requirements

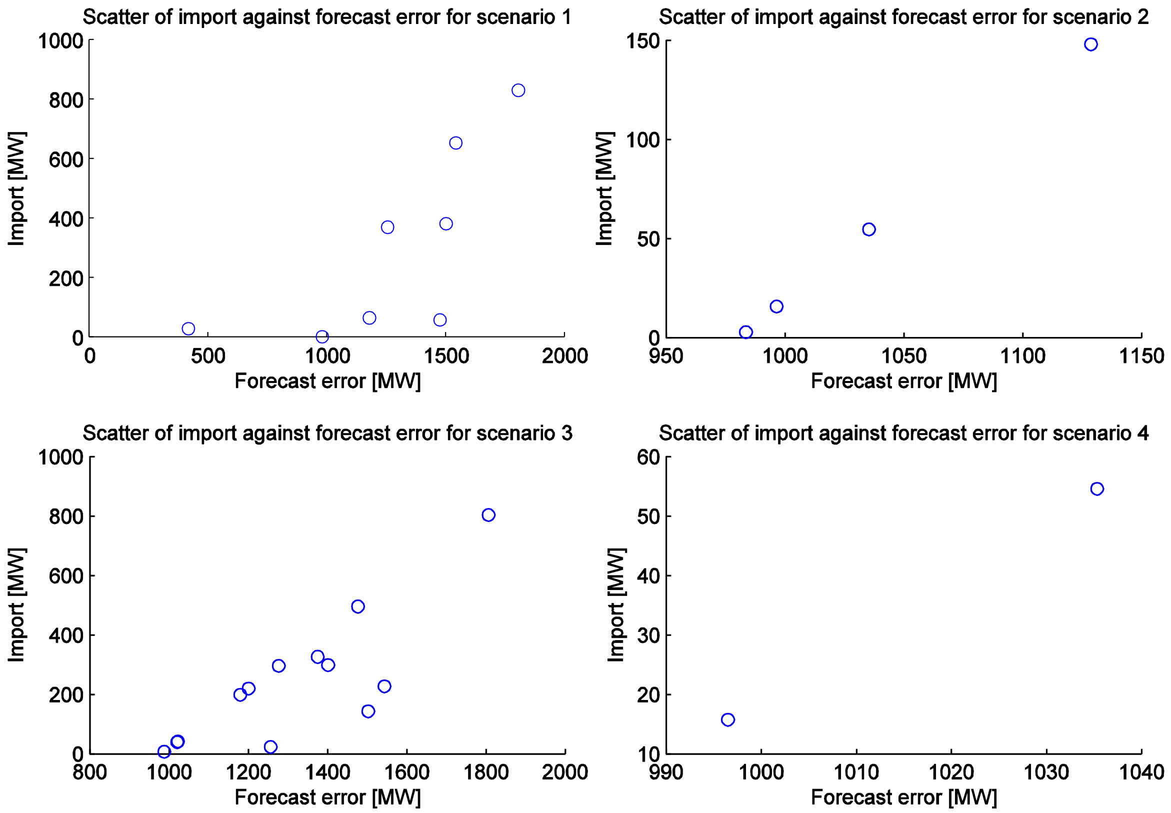

Figure 25: Relation between forecast error and import requirements.

Table 16 gives an overview of the results obtained for the base case with respect to the security of supply. More specifically, the frequency of the standing reserve capacity and import used together with the amount of energy generated by these peak power units and energy delivered through import are shown.

Table 16: Figures concerning the use of standing reserves and import for the base case.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Frequency of peak power used	77	63	95	64
Energy delivered by peak power plants [MWh]	27961	18180	35831	16822
Frequency of import used	8	4	13	2
Energy imported [MWh]	2378.8	221.1	3120.4	70.3

Effect of increasing spinning reserve capacity on operational efficiency

Figure 26 illustrates that increasing spinning reserve capacity from 300 MW towards 1055 MW does not impose a real change in CO_2 emissions output. The same level of CO_2 emissions is still obtained when running the 40 simulations for each of the scenarios considered.

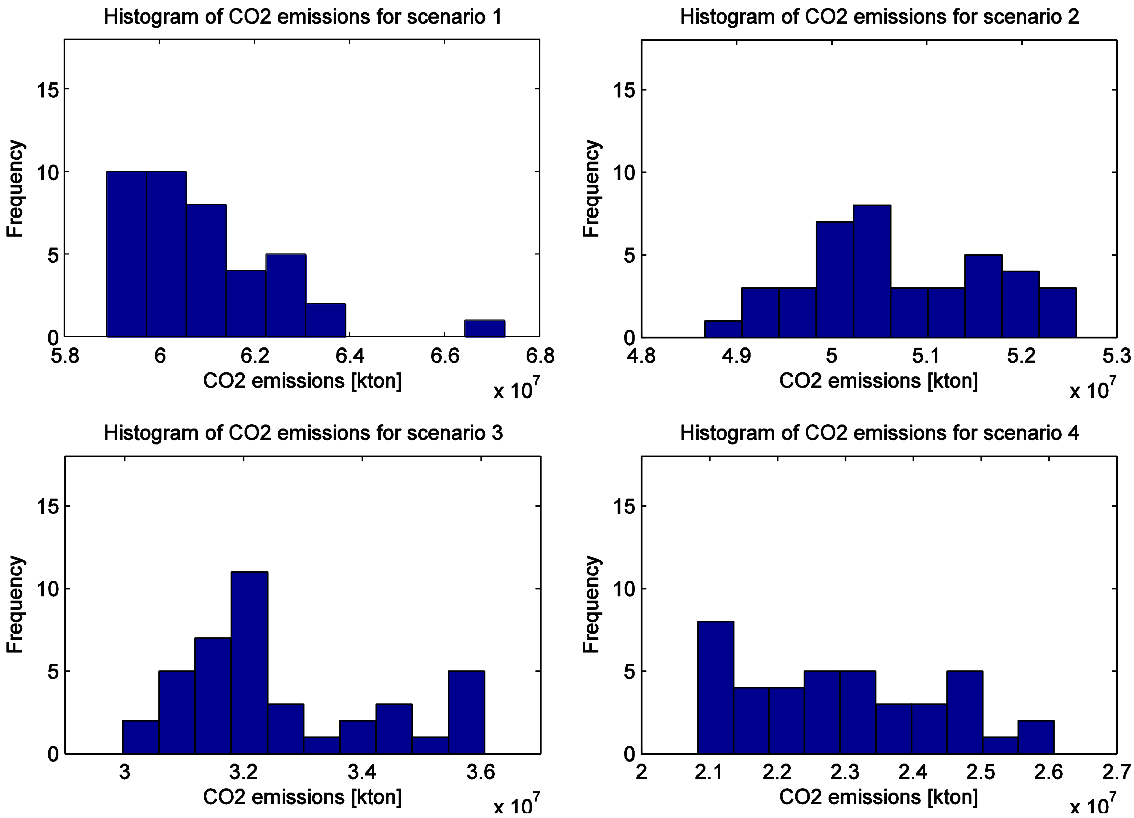

Figure 26: CO_2 emissions for all four scenarios after increasing spinning reserve capacity.

Effect of increasing spinning reserve capacity on security of supply

Figure 27 and Figure 28 show that increasing spinning reserve capacity decreases the use of real peak power and by consequence increase security of supply. The increased spinning reserve capacity is better capable of balancing forecast errors larger than 300 MW in the system, and thereby relax the efforts of the standing reserve capacity. Moreover, because spinning reserve capacity is increased with 755 MW, also import requirements are reduced. This is shown in Figure 29, where it is clear that only scenario 1 and 3 require at one time some import. Increasing spinning reserve capacity leads by consequence to a system that is more secure, however, this increased amount of reserve capacity is not realistic to attain in reality. The same conclusions can clearly be drawn from Table 17, where a decrease in frequency and delivered energy level can be seen for both standing reserve capacity and import in comparison with the base case. Export is again not used in any of the scenarios considered.

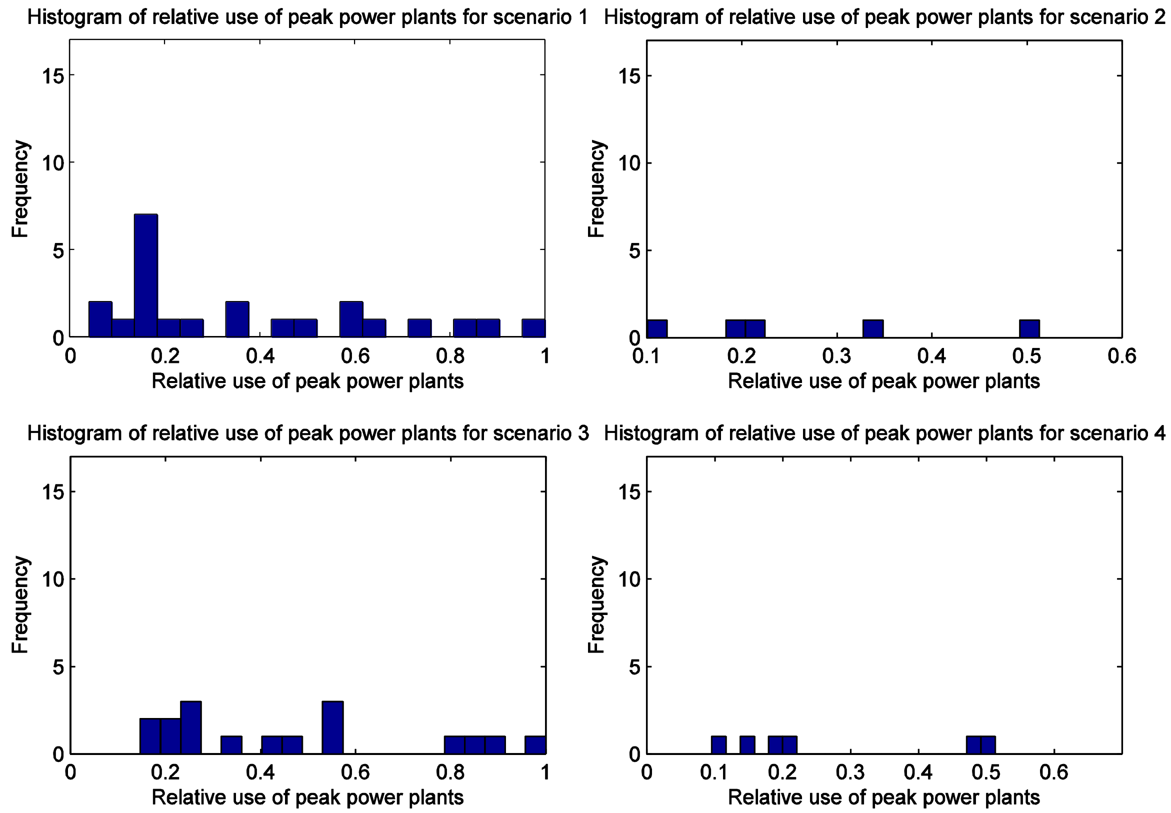

Figure 27: Frequency of the use of peak power plants after increasing spinning reserve capacity.

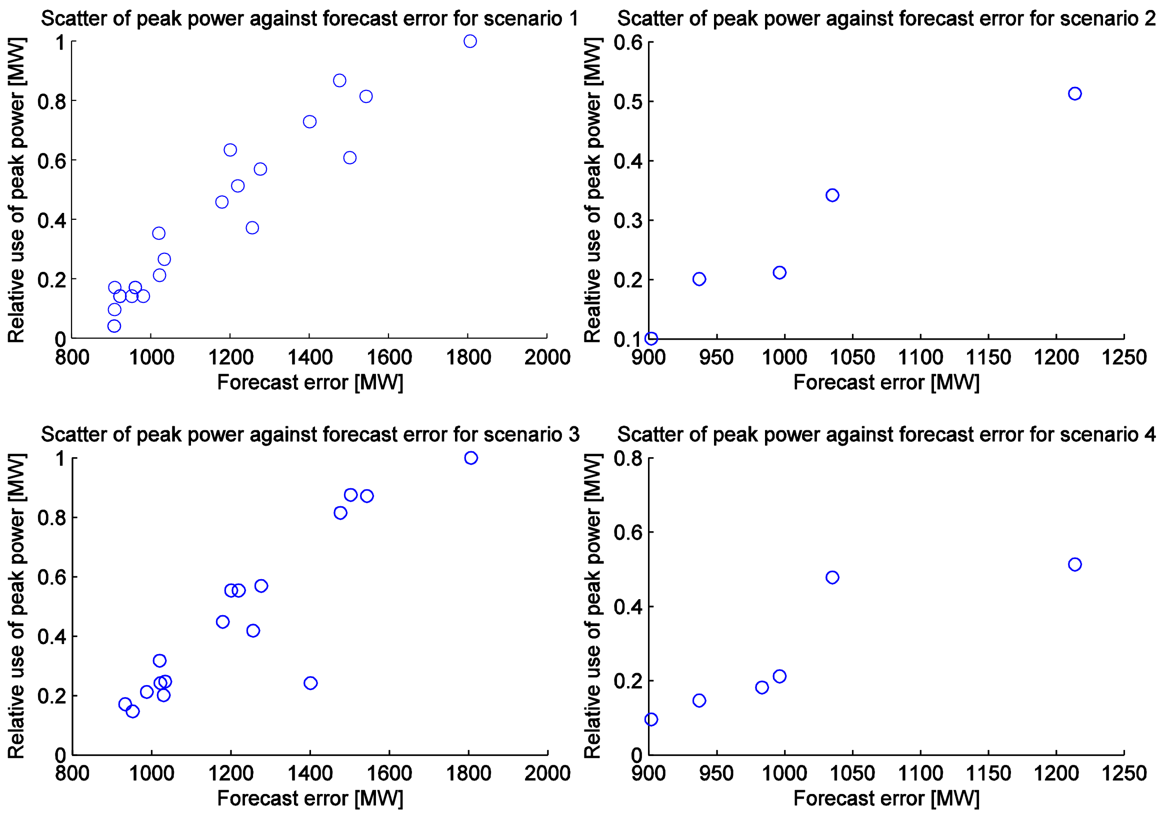

Figure 28: Relation between forecast errors and peak power requirements after increasing spinning reserve capacity.

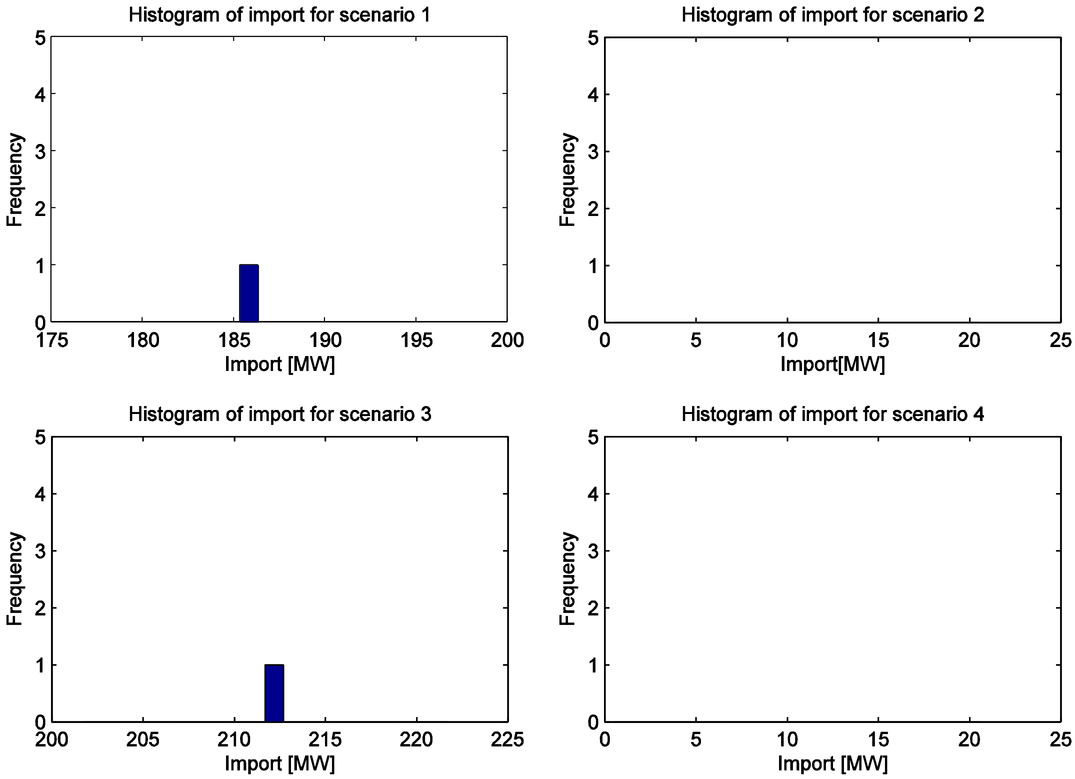

Figure 29: Frequency of import power requirements after increasing spinning reserve capacity.

Table 17 Figures concerning the use of standing reserves and import after increasing spinning reserve capacity. Between brackets, the relative difference with the base case is shown.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Frequency of peak power used	23 (-70%)	5 (-92%)	17 (-85%)	6 (-91%)
Energy delivered by peak power plants [MWh]	6079.7 (-78%)	1004 (-94%)	5809.3 (-84%)	1154.5 (-93%)
Frequency of import used	1 (-88%)	0 (-100%)	1 (-92%)	0 (-100%)
Energy imported [MWh]	185.8 (-92%)	0 (-100%)	212.2 (-93%)	0 (-100%)

B. Simulation phase 2: results

CCGT

Due to fact that the model works on an hourly time-scale and spinning reserves are held constant to 300 MW, adding extra CCGT power plants will have no effect on the flexibility of the Belgian power system in balancing forecast errors, since most power plants have, on an hourly dimension, ramp rates in the same order as CCGT power plants. Only when looking to a time scale of 15 minutes, CCGT power plants will probably have more effect on flexibility. However, it has to be said that also nuclear power plants can change their output within 10 minutes between 60% and 100% of their capacity (VGB PowerTech, 2010).

More effect of CCGT power plants will be seen on CO_2 emissions, if fuel switching would occur. However, taking fuel cost as projected by IEA, NEA and OECD (2010) leads to the result that coal would be less expensive than gas-fired power plants, even with a CO_2-tax of 30 euro per ton CO_2 emitted. This results in a unit commitment schedule where coal-plants will be scheduled before CCGT power plants, having by consequence no effect on CO_2 emissions. The authors notice, however, that the coal price, as represented by IEA, NEA and OECD, is quite low. Increasing this coal price would yield different results. Also a higher CO_2 price, which off course can be attained by 2020, could yield other results.

Decentralised storage

In a third case, 150 MW of decentralised storage is added to the reference case where 300 MW of spinning reserves are imposed. These decentralised storage units are modelled in the same way as the pumped storage units of Coo, but with less installed capacity at their disposal. In total, 40 units are installed in the Belgian system over 40 different nodes in the network. Each unit can store an energy content of 7.5 MWh, and has a nominal capacity of 3.75 MW. Results towards operational efficiency and security of supply are shown below.

Decentralised storage results concerning operational efficiency (CO_2 emissions)

Figure 30 shows CO_2 emissions for all scenarios in the case where 150 MW of decentralised storage is added to the base case. Comparing Figure 30 with Figure 18 makes clear that adding 150 MW of decentralised storage does not impose a significant change in CO_2 output.

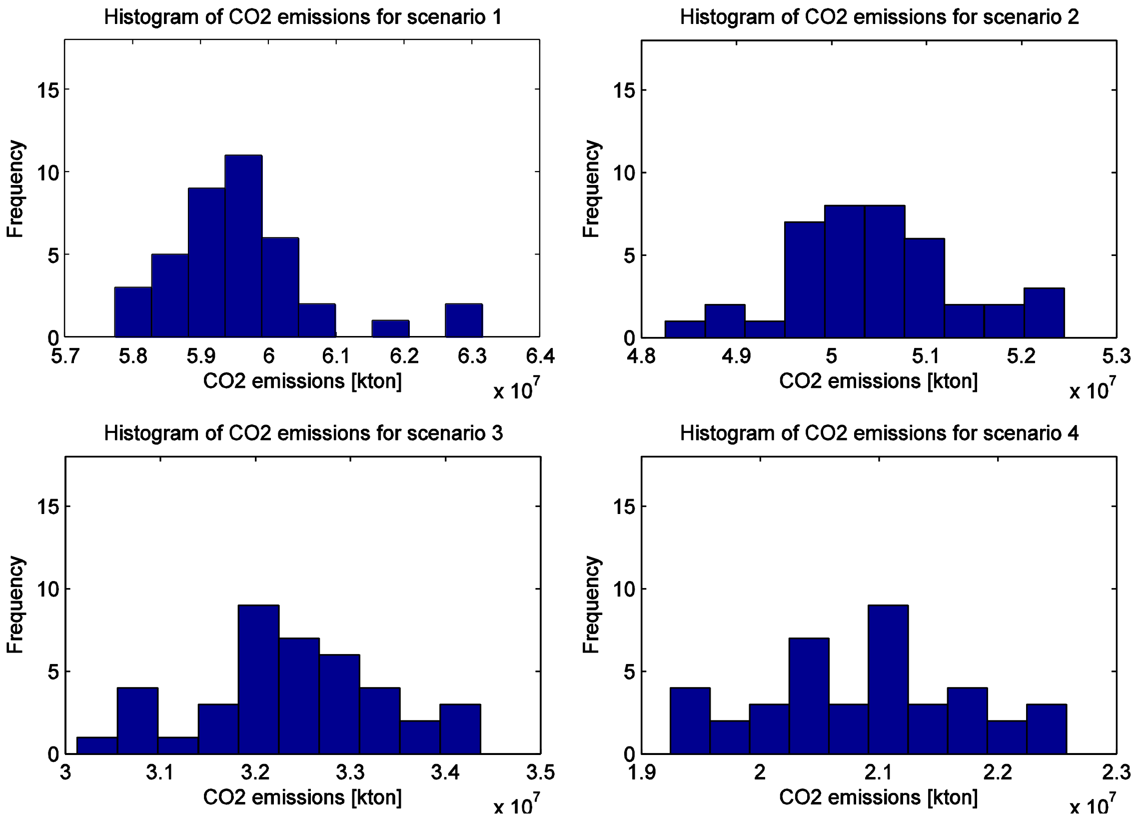

Figure 30: CO_2 emissions for all scenarios when 150 MW of decentralised storage is added to the base case.

<u>Decentralised storage results concerning security of supply (use of standing reserve capacity and import)</u>

Figure 31 to Figure 34 deals with the security of supply of the Belgian power system when 150 MW of decentralised storage is added. Also here, comparing Figure 31 to Figure 34 with Figure 22 to Figure 25 and looking at Table 18 shows that security of supply level stays more or less the same. Although the use of import is slightly decreased through the use of decentralised storage units, no clear conclusion can be drawn since over all scenarios together, the frequency of standing reserve capacity used is increased. Two reasons can be subscribed to these results. Firstly, the marginal increase of 150 MW of decentralised storage is probably too small to have any effect. Increasing this amount would probably yield a more extended effect. Secondly, studying the results in more detail showed that some results were due to the way in which the decentralised storage facilities are implemented in the model. More specifically, these decentralised storage units can, just like the pumped storage facilities, decide to release less energy or absorb (more) energy from the system during a dispatch hour in order to fulfil upcoming uncertain demand. This decision increases demand and thereby requires standing reserve capacity, even when spinning reserve capacity was sufficient to cover the imbalance (especially in scenario 3 and 4).

However, it has to be said that such strategic decisions still can be made in practice in order to prevent load shedding in the future. Modelling these decentralised storage units in a more detailed manner would probably yield some better results. More specifically, the model could be adapted such that in each actual dispatch hour, the forecasts of the closest upcoming hours (which are taken into account by the pumped storage and decentralised storage units) would already be improved. This would represent in a way an intraday trade for the storage units, and thereby temper the decision to release less energy or absorb (more) energy from the system in order to fulfil upcoming uncertain demand. Another possibility would be to exclude the decentralised storage units from further planning and to only use them for short-term balancing. This topic is going to be investigated and elaborated in more detail in the near future.

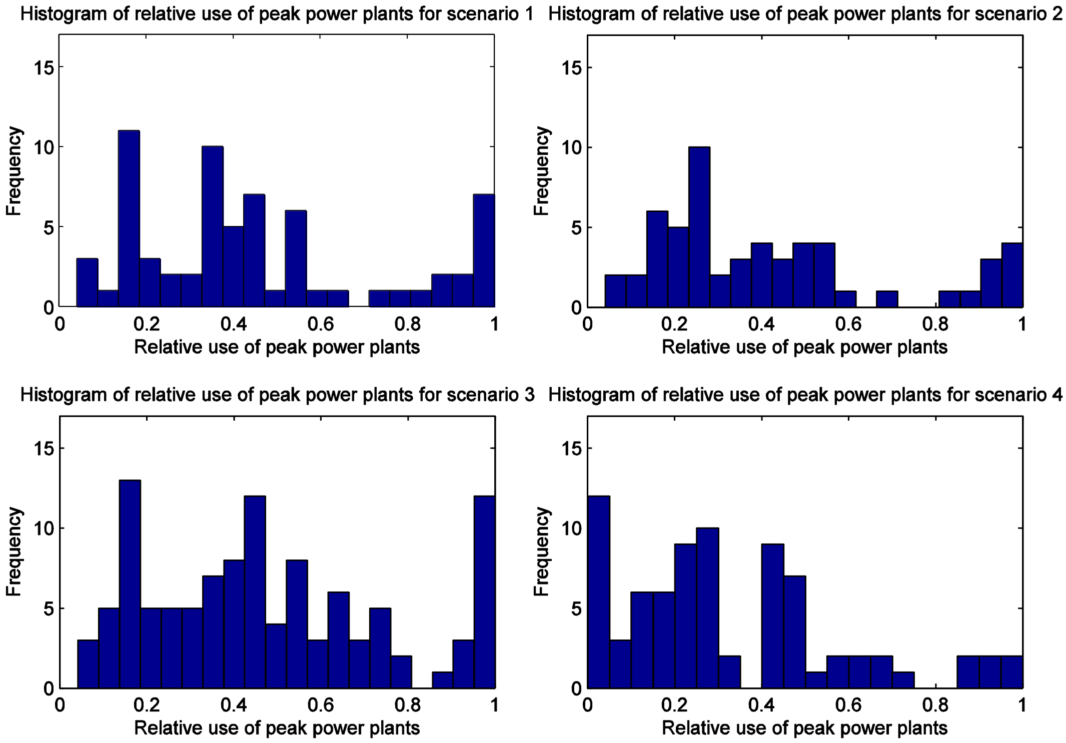

Figure 31: Frequency of the use of peak power plants when 150 MW of decentralised storage is added to the base case.

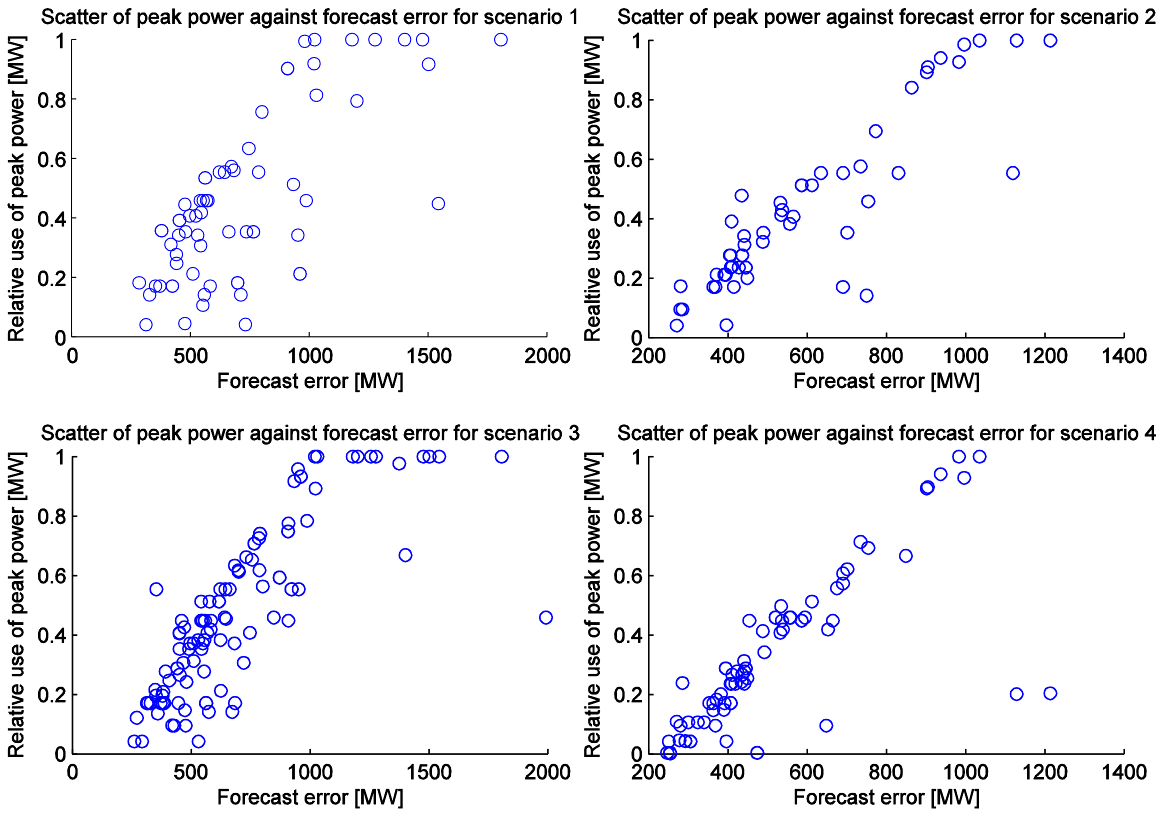

Figure 32: Relation between forecast errors and peak power requirements when 150 MW of decentralised storage is added to the base case.

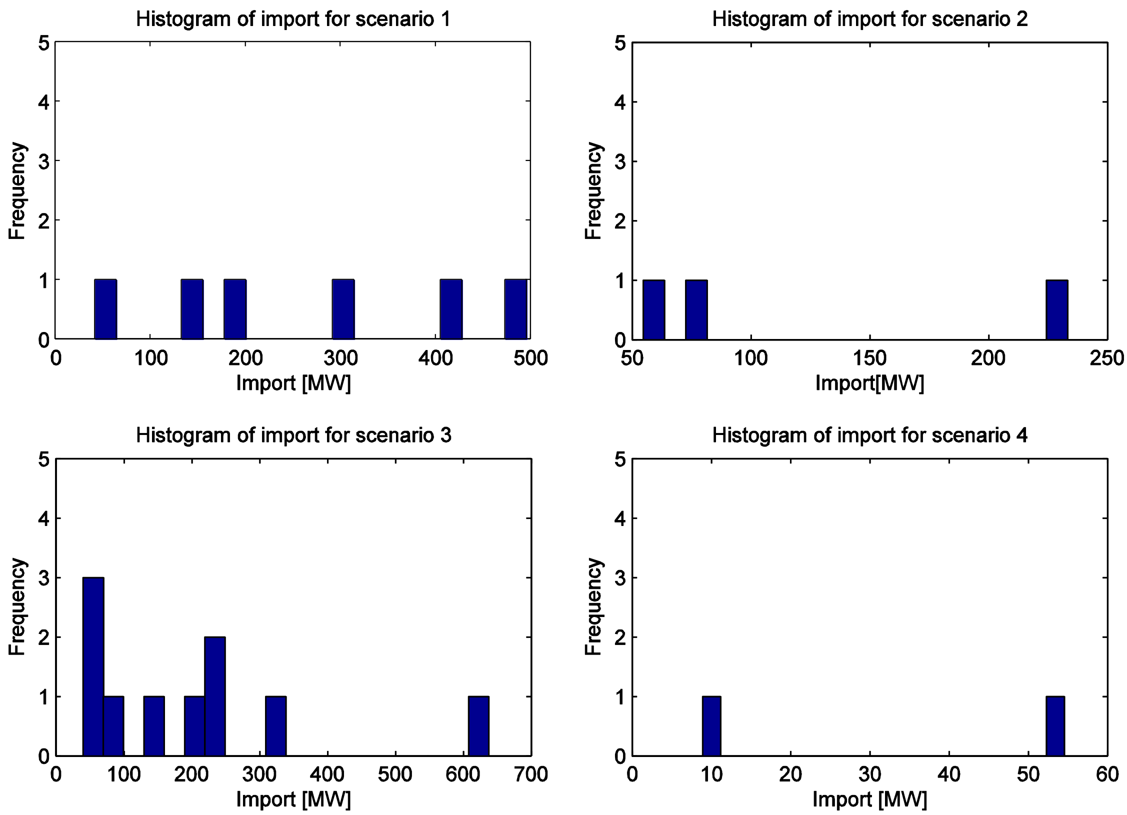

Figure 33: Frequency of import requirements when 150 MW of decentralised storage is added to the base case.

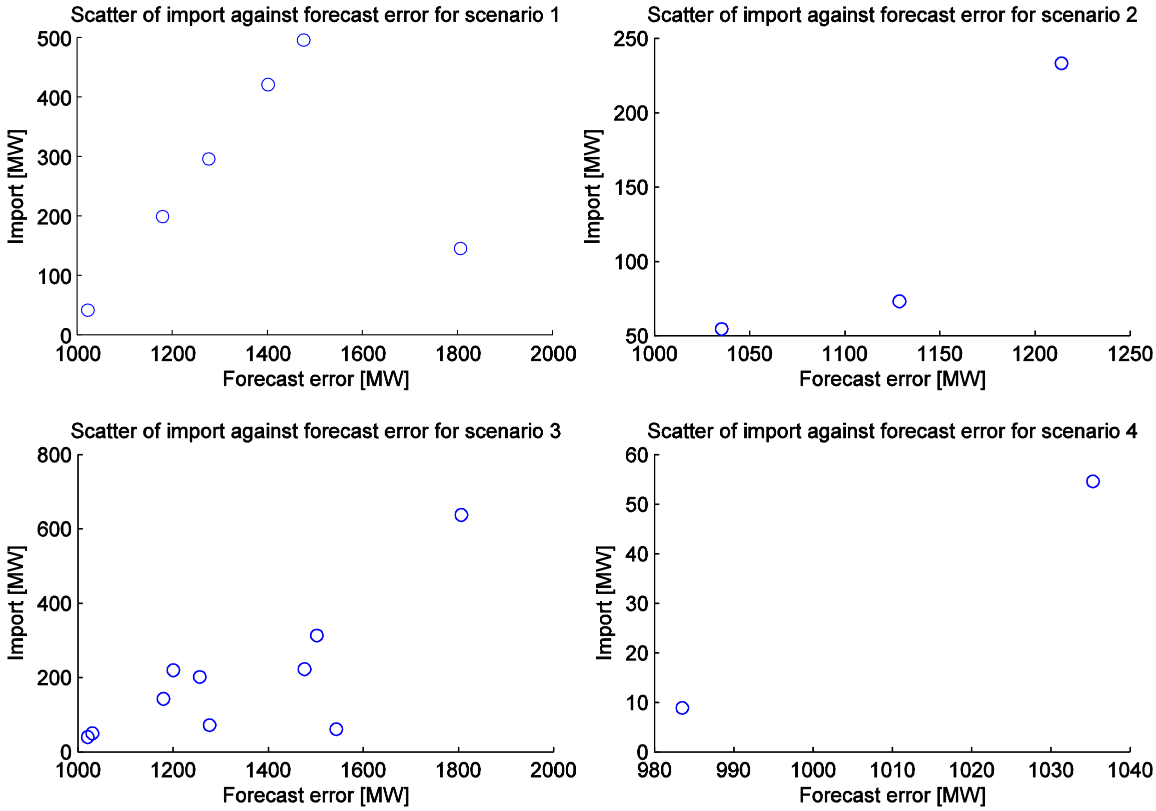

Figure 34: Relation between forecast errors and import requirements when 150 MW of decentralised storage is added to the base case.

Table 18: Figures concerning the use of standing reserves and import when 150 MW of decentralized storage is added to the base case. Between brackets, the relative difference with the base case is shown.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Frequency of peak power used	67 (-13%)	56 (-11%)	110 (+16%)	78 (+21.9%)
Energy delivered by peak power plants [MWh]	22245 (-20%)	17170 (-6%)	38691 (+8%)	18686 (+11%)
Frequency of import used	6 (-25%)	3 (-25%)	10 (-23%)	2 (0%)
Energy imported [MWh]	1598.4 (-49%)	360.9 (+63%)	1960 (-37%)	63.4 (-10%)

Demand side response

In this fourth and last case, 1000 MW of demand side response (DSR) is added to the reference case. DSR is modelled in such a way that it can only be used by the TSO during every hour of the economic dispatch phase. When making the unit commitment schedule, no demand can be shifted.

During every hour of the ED phase, the system operator has the possibility to lower or increase demand with maximum 1000 MW, with the extra constraint that at the end of every day (at the end of every 24 hours) the balance of every pre-scheduled and postponed demand must be zero. Although this representation of DSR is rather simplistic, it still makes it possible to draw some strong conclusions about the effect of implementing such a huge amount of DSR. Results are shown below.

Demand side response results concerning operational efficiency (CO_2 emissions)

Also in this case, with the addition of 1000 MW DSR, the output of the model shows no significant difference in operational efficiency. CO_2 output stays at the same level as in the reference case.

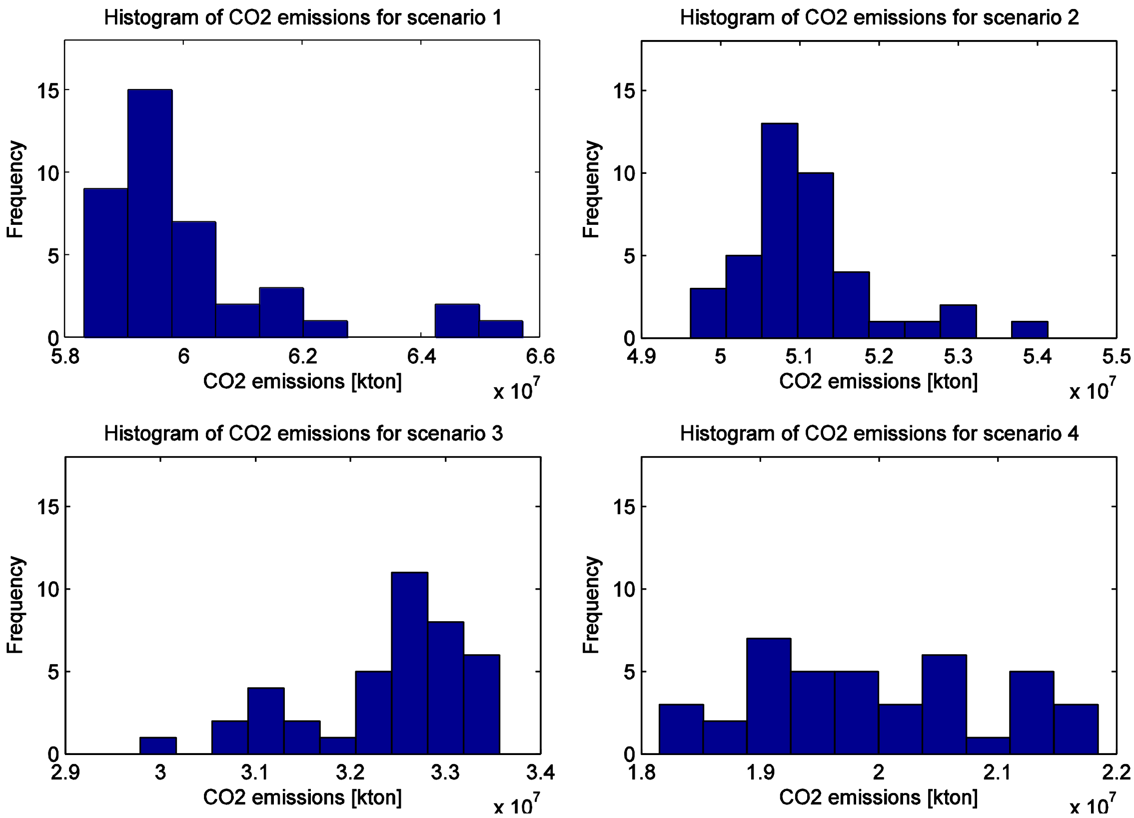

Figure 35: CO_2 emissions for all scenarios when 1000 MW of DSR is added to the base case.

Demand side response results concerning security of supply (use of standing reserve capacity and import)

Looking to the use of standing reserve capacity and import gives some very interesting results. Simulations show that both the use of standing reserve capacity and the use of import is decreased when adding an amount of 1000 MW of DSR to the Belgian power system.

This means that demand side response is of good help in balancing wind forecast errors. These results can be concluded by comparing Figure 36 to Figure 39 with Figure 22 to Figure 25 and considering Table 19.

Remark, however, that increasing spinning reserve capacity with 755 MW gives much better results with reference to security of supply than adding 1000 MW of DSR to the system. From Table 20, it can be concluded that import and standing reserve capacity is used less in the case where spinning reserve capacity is increased. Furthermore, this difference will probably be larger than shown here, since DSR is modelled rather simplistic. If DSR is going to be modelled to a much larger detail, than constraints much probably be added thereby reducing positive results. However, when comparing both cases, one has to take into account the costs of increasing and using spinning reserve capacity, and adding and using DSR to the system.

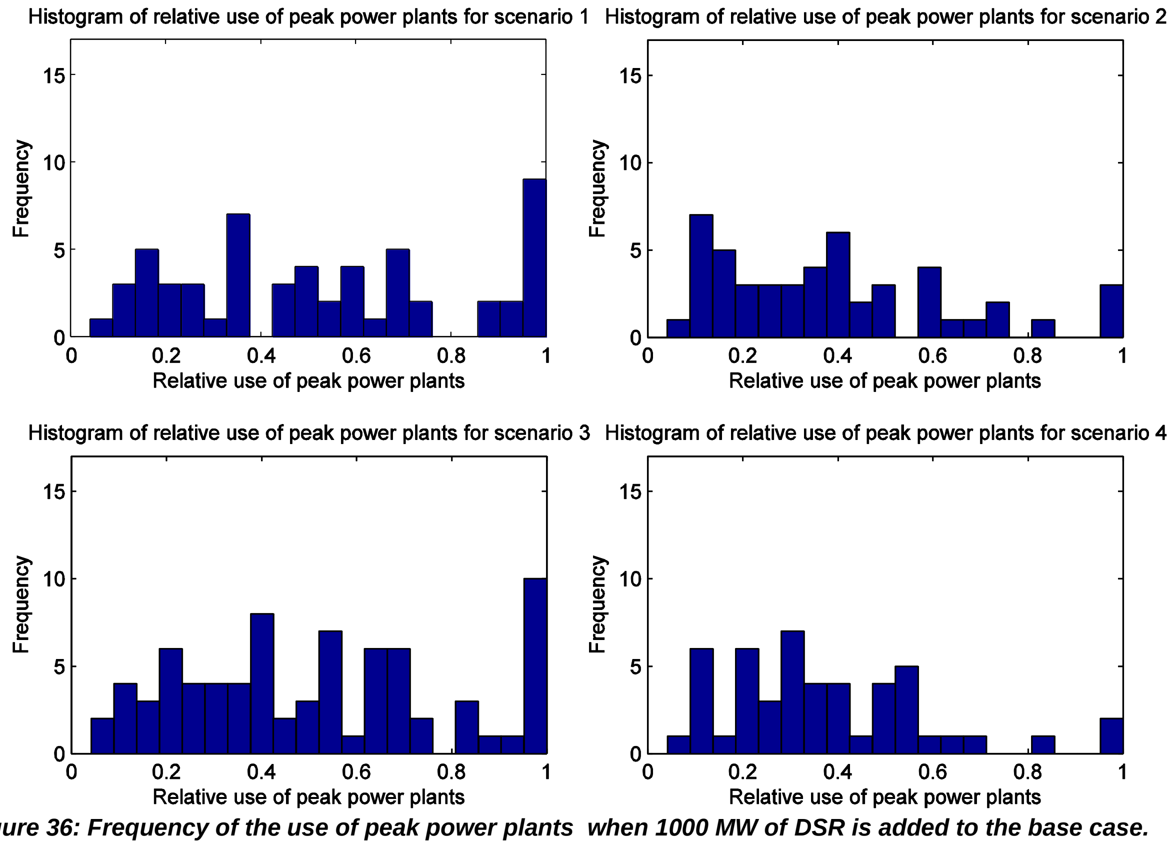

Figure 36: Frequency of the use of peak power plants when 1000 MW of DSR is added to the base case.

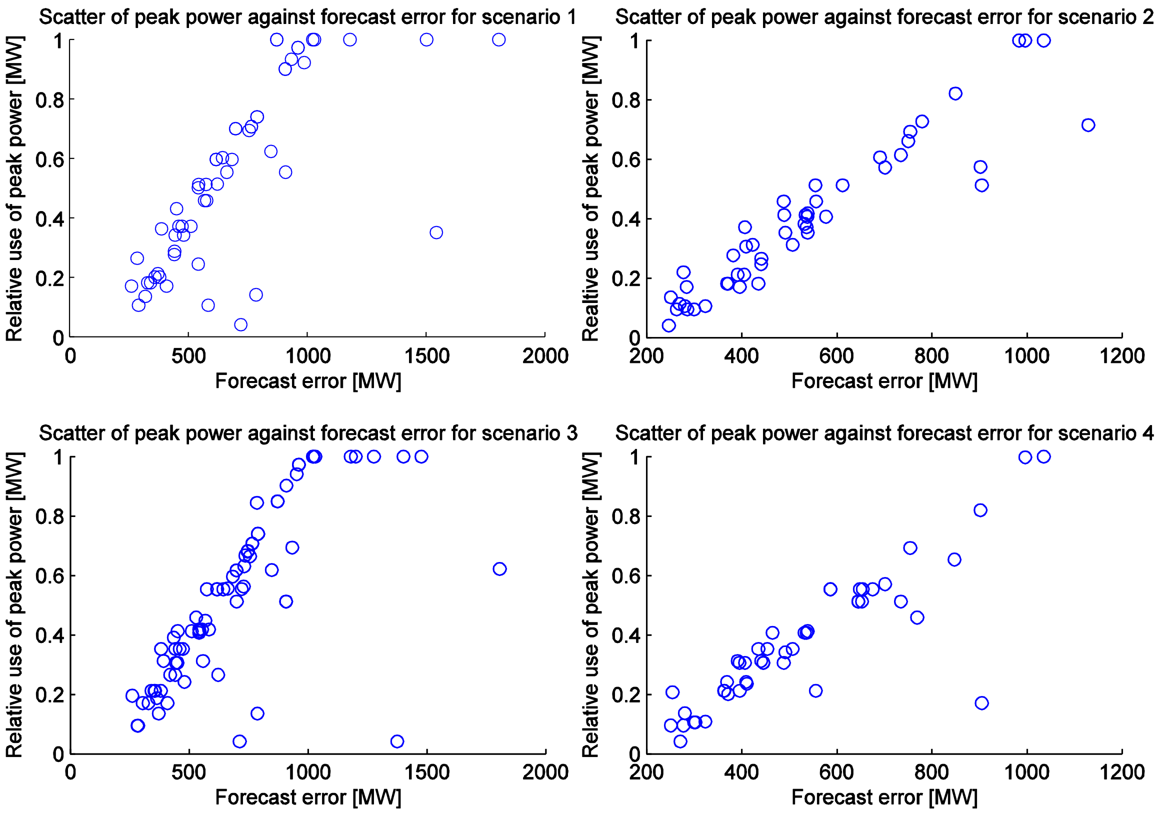

Figure 37: Relation between forecast errors and peak power requirements when 1000 MW of DSR is added to the base case.

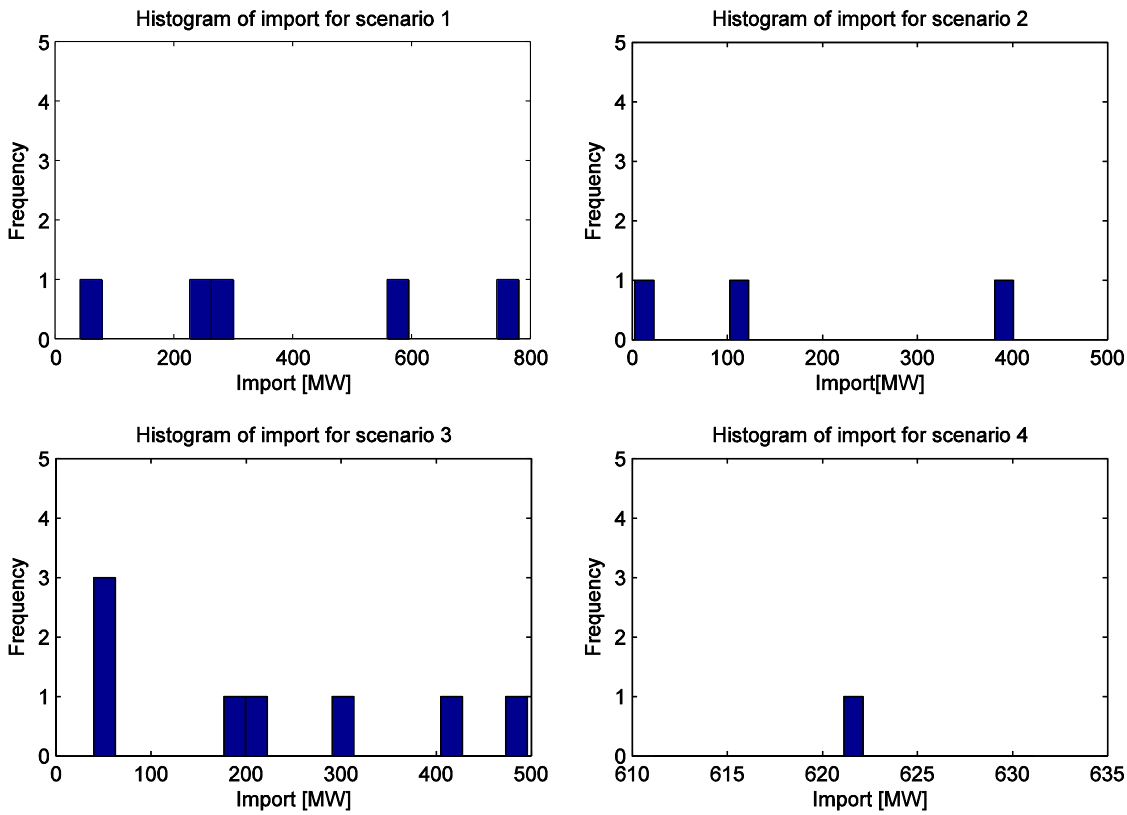

Figure 38: Frequency of import requirements when 1000 MW of DSR is added to the base case.

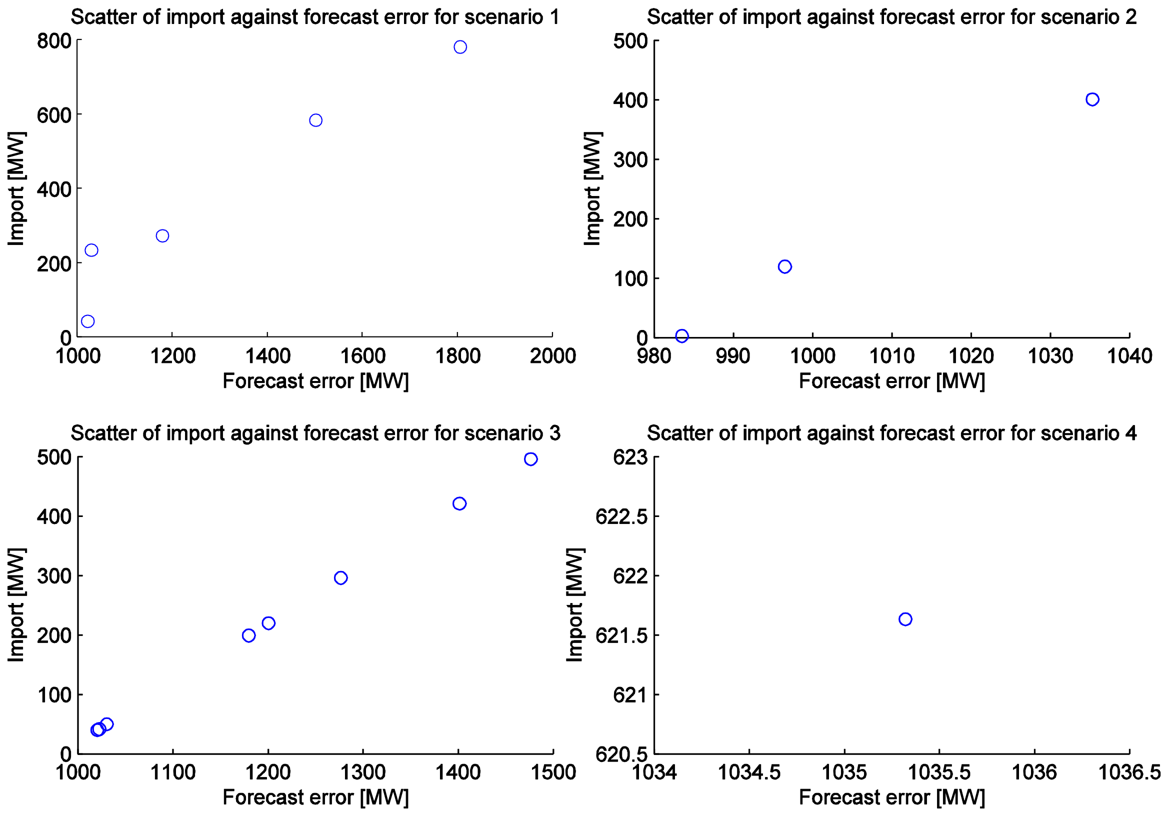

Figure 39 Relation between forecast errors and import requirements when 1000 MW of DSR is added to the base case.

Table 19: Figures concerning the use of standing reserves and import when 1000 MW of DSR is added to the base case. Between brackets, the relative difference with the base case is shown.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Frequency of peak power used	57 (-26%)	49 (-22%)	77 (-19%)	48 (-25%)
Energy delivered by peak power plants [MWh]	21803 (-22%)	14263 (-22%)	29218 (-18%)	13294 (-21%)
Frequency of import used	5 (-38%)	3 (-25%)	8 (-38%)	1 (-50%)
Energy imported [MWh]	1909.5 (-20%)	523.3 (-58%)	1762.4 (-44%)	621.6 (+784%)

Table 20: Relative difference between case with increased spinning reserve capacity and case with addition of DSR. A negative sign means a decrease in increased spinning reserve case relative to the DSR case.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Relative difference in the use of peak power	-60%	-90%	-78%	-88%
Relative difference in energy delivered by peak power plants	-72%	-93%	-80%	-91%
Relative difference in the use of import	-80%	-100%	-88%	-100%
Relative difference in energy imported	-90%	-100%	-88%	-100%

C. Conclusions and recommendations

Conclusions

In view of meeting renewable energy targets towards 2020, various renewable development scenarios are developed for Belgium. Concerning wind, the national renewable energy action plan targets an installed capacity of 4320 MW in 2020. Factually, this scenario is still rather conservative compared to other projections that have been put forward.

Different studies have shown that the installation of large amount of a variable RES-E in the power systems results in various challenges concerning network and generation adequacy. The objective of the final project task is to identify barriers and necessary measurements for facilitating 4320 MW of wind by means of power system simulations based on UC-ED with network constraints (DC load flow). Wind is integrated in a model representing the Belgian power system including scheduled investments towards 2020.

System simulations are performed for different wind generation and demand scenarios. Four scenarios are designed with two different load profiles (high - low) and wind power generation profiles (stable - variable). Forty synthetic forecast profiles are applied to each scenario. In addition, four cases are designed representing different combinations of wind balancing technologies presented in Task 7. These are evaluated on their impact on operational efficiency and security of supply.

The first simulations reveal major integration problems as the generic model seems to be unable to facilitate the 4320 MW of wind distributed over the control zone. Network constraints occur in the coastal region (due to large offshore capacities) and in the South of Belgium (less meshed grid). A series of additional grid reinforcements are proposed and included in the model.

A second barrier for large wind power integration is the alleged inflexibility of the nuclear park as currently operated (in base load). Low demand combined with high wind generation may result in net demand lower than the base load nuclear park. Therefore, this study proposes to increase flexibility of the generation park by operating the nuclear power plants in modulating mode (as is done in France). This measure is also included in the model. A final barrier originates from the large imbalances which may occur due to wind-forecasting errors. Predefined capacity of 300 MW spinning reserves and 737 MW standing reserves may not be adequate to balance wind power imbalances. Increasing the amount of reserves in order to be able to cover the largest possible forecast error may be unrealistic in the framework of generation adequacy.
Therefore, in a final step, import and export are allowed in real-time at artificial high costs. This maintains the incentive to cover imbalances on a national level: import can be seen as the additional upward reserves required and export as the downward reserves or curtailment.

After these necessary adaptations to the model are made, the simulations of the base case (no additional wind balancing technologies) can be performed. The focus is on operational efficiency and security of supply. The results reveal that nuclear regulation is needed mostly when a high wind power output is present during low demand[16]. Furthermore, peak power is used regularly in all four scenarios when only 300 MW of spinning reserve capacity is demanded from the system. Also import is required in order to balance the largest forecast errors. Export on the other hand is not used because nuclear power is assumed to be able to regulate its power output down to 60% of its rated power. Increasing the amount of spinning reserves to 1055 MW reduces both the use of peak power and the import requirement, leading by consequence to a more secure Belgian power system. No effect on CO_2 emissions is noticed. However, this increase in spinning reserve capacity is not realistic to attain.

In this study, the focus is on the ability of the power system to balance wind power with national resources. The use of peak power plants and import is seen as a “problem” for security of supply and represent additional reserve capacity. Three technology cases, representing CCGT, decentralised storage and demand-side response, are therefore compared with the base case on this use of standing reserve capacity and import. Additionally, operational efficiency is investigated.

[16] This is not necessarily true when including export as nuclear generation is likely to be under the market price on international markets.

Due to fact that the model works on an hourly time-scale and spinning reserves are held constant to 300 MW, adding extra CCGT power plants will have no effect on the flexibility of the Belgian power system in balancing forecast errors. Only when looking to a time scale of 15 minutes, CCGT power plants will probably have more effect on flexibility. More effect of CCGT power plants will probably be seen on CO_2 emission, if fuel switching would occur. This is, however, not the scope of this report. Adding in a third case decentralised storage units to the Belgian power system does not change the results to a significant extent.

This is probably due to the small amount of decentralised storage added to the Belgian power system and the fact that a large amount of wind power integrated in the Belgian system (4320 MW) leads to some extent to large changes in power output. These large changes cannot be covered by such a small addition of decentralised storage. However, storage can still have an important economic impact on daily situations. Extending the amount of decentralised storage would probably yield more extended results, but is unrealistic to obtain against 2020. Furthermore, modelling these decentralised storage units in a more detailed manner would probably yield some better results. This topic is going to be investigated and elaborated in more detail in the near future. Last but not least, the base case is extended with 1000 MW of demand side response. Also in this case, with the addition of 1000 MW DSR, the output of the model shows no significant difference in operational efficiency. The use of standing reserve capacity and import decreases however in all scenarios considered, meaning that DSR is of good help in balancing wind forecast errors. Increasing spinning reserve capacity with 755 MW, however, gives much better results with reference to security of supply, than adding 1000 MW of DSR to the system. In this comparison, costs of increasing and using spinning reserve capacity, and adding and using DSR to the system is not taken into account.

Recommendations

As these results show, the integration of 4320 MW of wind power in the power system is not straightforward without depending on the import from and export. System simulations based on a UC-ED model of the Belgian power system identify three technical barriers to be overcome:

1. Network reinforcements are needed in the coastal area to facilitate offshore wind power and in the South of Belgium since the network there is less meshed than in the rest of Belgium. Further research is to be directed to detailed network simulations (AC load flow).

2. Operate the existing nuclear power plant in modulating mode (cfr. France) in order to be able to reduce load in moment of low net demand (low demand, high wind generation). Further research is to be directed to the technical feasibility and economic cost of such measure.
3. Integrate flexible technologies delivering capabilities to balance real-time wind power imbalances. Alternatively, this may lead to the import of real-time balancing power. Further research is to be performed towards the research of optimal combinations of technologies to cover for wind power imbalances.

3. POLICY SUPPORT

As part of the European energy policy goals of sustainability, security of supply and improved competitiveness, the share of Renewable Energy Sources for Electricity (RES-E) is targeted to rapidly increase. The 2009 EU Renewable Energy Directive (2009/28/EC) foresees to increase the share of renewable energy in the EU up to 20% of the final energy demand. In this directive, the Belgian national target is set at 13%. The Belgian Renewable Energy Action Plan, presented to the European Commission in November 2010, targets the achievement of a renewable share of 21% of final energy demand in the electricity sector (in contrast to 10% and 12% respectively in transportation and heating and cooling). Major contributors to these objectives are expected to be wind power (4320 MW, 10.47 TWh/year), bio-energy (2452 MW, 11.04 TWh/year) and solar PV (1340 MW, 1.14 TWh/year).

Due to the nature of wind power, integration of large shares is expected to introduce technologic, economic and regulatory challenges to the power system which is historically based on conventional and centralised generation. Objective of this project is to identify barriers for wind power integration and to analyse how they can be overcome. Results allow Belgian policy makers to pursue the required actions to enlarge wind power potential in Belgium.

In a first part of the project, the market value of wind is modelled for a single wind power plant. This market simulator allows to researching the impact of market design on wind power profitability. In a second phase, the Belgian power system is modelled in order to identify technical barriers for wind power integration. In a third and final phase of the project, technological measures and market mechanisms are presented in order to assess their potential for wind power facilitation.

3.1 Integration of Wind Power in Power Markets

3.1.1 Production Support

Wind power is currently supported in Belgium on multiple governmental levels. The support mechanism applied is in principle based on green certificates implemented both on federal as on regional level.

The mechanism is installed for offshore wind power generation falling under federal policy: each generated MWh of renewable energy is granted with a green certificate to be bought by the transmission system operator, i.e. Elia.

Minimal price is currently set at 107 €/MWh or 90 €/MWh for capacities larger above the first 216 MW of the same project. A rough estimate of these costs results in a yearly amount of 630 M€ only for an offshore capacity of 2000 MW[17] which is the expected by 2020. These costs are entirely passed to the consumer through the transmission tariffs.

Onshore wind, part of regional policy is submitted to a similar system of green certificates with slight differences depending on location and grid connection level. Certificates for wind power plants in Flanders receive one certificate for each MWh of renewable generation. These certificates can be sold on a market based on quota obligations for power suppliers by means of bilateral trading or the Belpex Green Certificate Exchange. Alternatively, these certificates can be sold at a minimal price of 80 €/MWh to the distribution system operator, if the plant is connected to the distribution level ($\leq$ 70kV) or at 50 €/MWh if connected to the transmission level ($>$ 70 kV). These certificates can be resold on the market to recuperate part of the costs. In Wallonia, in contrast to Flanders, one certificate does not represent 1 MWh of electricity generated, but is determined on CO_2 offset with respect to a reference being the combined cycle power plant. These certificates can again be sold on the Belgian market for green certificates. Alternatively, certificates can be sold to the transmission system operator at 65 €/MWh which can resell them on the market. Prices on the Belpex GCE vary from 79 to 87 €/MWh between 2009 and now.

This support mechanism is expected to result in elevated costs when extrapolated to projections towards 2020. Studies stress the impact on costs of electricity for the consumer and advise revisions for future installations. This issue is not further dealt with in this project.

3.1.2 Market Value of Wind Power in Power Markets

A. Market Context

Wind power generators can sell electricity on different markets. First of all, long term contracts are used to sell expected generation by means of multi-year, yearly, seasonal and monthly contracts. One day before generation, weather prediction models are able to provide relatively accurate output predictions giving the ability to correct positions by means of day-ahead contracts. This is facilitated by means of a Belgian spot market, i.e. Belpex Day-Ahead Market through anonymous trading of standardised hourly market instruments.

[17] As determined by means of a capacity factor of 35%.

Market parties can submit their bids for the next day until 12h day-ahead, i.e. market closure. The forward character of electricity trading is explained by the nature of power systems: safe system operation requires real-time equilibrium between demand and generation. This condition is combined with certain inflexibilities in generation and demand requiring a high level of system planning. This is ensured by the transmission system operator which requires the communication of all market positions one day before real time, i.e. 14h or 15h respectively for demand or injections, to ensure safe operation of the power system.

Wind power predictions are characterised by a level of uncertainty, which is aggregated with other sources of uncertainty resulting from demand predictions, output predictions of other variable renewable sources (e.g. solar PV) or unscheduled outages of conventional power plants. New information received after gate closure allows market players to correct positions by means of managing their portfolio or intraday trading. The intraday trading platform enables market players to execute energy transfers real-time as they have to submit these nominations to Elia on the next day. In order to facilitate trade, an intraday market is opened on the Belpex platform allowing to trade with parties with opposite deviations or flexible assets. However, this market suffers from low liquidity.

In order to operate in electricity markets, every market player is required to be or have a contract with a Balancing Responsible Party. This entity ensures the balance between demand and generation in its portfolio over each time period of 15′, i.e. the settlement period. Real-time imbalances may lead to system imbalances when aggregated over the control zone and endanger system stability. This is resolved by the transmission system operator activating contracted reserve power. These reserves are procured from the market and costs are transferred to the responsible entities by means of imbalance tariffs and the imbalance settlement mechanism. This is generally referred to as the balancing market.

B. Market Value of Wind Power

The major contribution of the first phase of the project is the development of a tool designed to the determine market value of wind power. This tool is based on a wind power generator trading its output on the Belpex Day-Ahead Market and facing imbalance tariffs on the balancing market. Results express the market value in €/MWh. It allows determining wind power revenues and profitability. This is extremely useful for wind power generators evaluating investments e.g. location, turbine technology, prediction model, etc.

Secondly, it may serve as a useful tool for wind power generators to negotiate long-term contracts and the result is therefore referred to as the fixed price OTC equivalent. Finally, the simulator allows policy makers to determine the effect of different support mechanisms on wind power profitability as well as to assess impact of different market design parameters. Such analyses are crucial for achieving a cost-effective policy supporting wind power developments.

Results show a market value of 66 €/MWh for a single wind turbine in 2009. These are based on electricity prices of 2002-2008 which do not take into account the effect of the financial crisis. Results depend largely on price assumptions and should therefore be compared relatively. Secondly, imbalance costs are determined at 18% of the total wind power revenues. Aggregation of wind turbines in power plants or regional parks shows a significant decrease in imbalance volume and cost. This is explained by correlation of the prediction error at different locations which is never 100%. Consequently, increasing the geographical range of balancing is expected to reduce imbalances. This argues for pan-European interconnections and facilitating cross-border market mechanisms.

Secondly, the increasing accuracy of wind power predictions shows large benefits concerning imbalance costs. It is shown that improved predictions may decrease imbalance costs by 12 €/MWh. This calls for increasing efforts in wind power prediction research which is properly incentivised by the imbalance settlement system. Additionally, this study shows the added value of using shorter prediction horizons decreasing imbalance costs up to 3.8 €/MWh. This number is expected to increase further with increasing accuracy of intraday predictions. In order to reap these benefits, market mechanisms are today not fully supporting the use of shorter prediction horizons. Market closure is set at 11h day-ahead while intraday markets show low liquidity and highly volatile prices.

C. Market Mechanisms for Balancing Wind Power

An important part of the project focuses on market integration of wind power. As increasing shares of wind energy are expected in the power system, necessary measures are to be undertaken to ensure full market integration. Wind power is characterised by a high investment cost, low variable costs and a variable generation profile. In order to ensure market competitiveness, a package of support measures is designed and implemented on different governmental levels which are already discussed above.

Variability of wind power has certain integration impacts on the electricity generation system. Variability requires a certain flexibility of the generation system worsened by its limited predictability. In the current market design, positions are scheduled day-ahead. Consequently, unpredicted power variations are to be balanced in real-time by flexible generators. In a worst case scenario, but often the case for small renewable players, this means relying on the balancing markets and its volatile, uncertain imbalance tariffs resulting in elevated imbalance costs reducing profitability of wind power.

In some power systems, wind power generators are exempted from balancing requirements. In Germany, wind power is procured at a feed-in tariff by the system operator which sells aggregated wind generation on the market. In Belgium, a specific regulation is installed which exempts a part of the offshore wind power generation from the existing imbalance settlement mechanism. Deviations from nominated generation which stay within a certain bandwidth around nomination are settled at a capped tariff reducing the costs and price risks for offshore wind power generators. Motivated by higher offshore imbalances, implementation of this mechanism is not transparent and highly complex. Additionally, results show a very limited financial impact (1.4 - 1.7 €/MWh) compared to the generation support.

Exempting wind power from balancing or capping imbalance prices has fundamental implications on market design. Such mechanisms cut the link between the procurement cost of reserves and the imbalance tariffs which is important from the viewpoint of correct price signals. It may reduce incentives for wind power generators to invest in management of their imbalance volumes resulting in a higher system impact and higher overall costs to the system. On the other hand, pressure on the balancing market due to offshore wind power generation is passed to other network users leading them to cross-subsidy wind power integration. This mechanism is assessed as contrasting to the objective of this project to enhance market participation of wind power.

Better is to research and implement a market design which can be used by wind power (and other generators) to manage their imbalances in a cost-effective way:

1. This study shows the positive effect of increasing the accuracy of wind power predictions. It is expected to significantly reduce imbalance costs, which is also the major incentive for research. Consequently, prediction tools are currently improving fastly.
2. In order to reap the benefits of increasing accuracy from shorter prediction horizons, generators must be given the opportunity to adapt positions after gate closure.

This can be ensured by delayed market or gate closure, currently respectively at 12 h and 14-15 h. Feasibility of adapting these market design parameters is to be checked with the system operator from the viewpoint of system planning and have to be dealt with on European level in order not to counteract on European harmonisation. Currently, this requirement is partially overcome by the introduction of intraday trading possibilities.

3. Intra-day trading mechanisms allow wind power generators to adapt positions due to updated predictions. They may find parties with counteracting imbalances or acquire capacity from conventional flexible generation sources. These mechanisms are gradually improved by introducing an intraday market on the Belpex platform and striving towards market coupling with neighbouring countries. However, liquidity on intraday markets remains low and is therefore not yet a full alternative for balancing wind power.
4. Another possibility is to use the own portfolio to balance wind power real-time. Portfolio management may reduce total imbalance due to limited correlation effects and available flexible capacity might be used for real-time balancing.

The fundamental issue remains the availability of flexible capacity in the power system. This may be procured nationally or internationally under the condition of sufficient interconnection capacity. Limited liquidity on the current intraday market is probably explained by the physical shortage of flexible capacity on the one hand and by the high concentration of generation capacity with a few market players on the other hand. It is therefore advised to enable investments in accessing additional flexible capacity locally and via interconnections to access foreign capacity. Current research focuses on the development and implementation of new technologies as demand-side management or decentralised storage equipment.

D. Wind Power as a Key Market Player

One of the main objectives of this research is to investigate market integration of wind power. In order to attain full market participation, one should not pursue mechanisms protecting wind from market risks. With the projected market share towards 2020, wind is becoming a key market player which should engage in full market participation. With quickly maturing technology and profitability, specific wind power support mechanisms are to be revised continuously to ensure a cost-efficient integration of renewable energy.

Different research projects focus on the possibility of wind power to participate in markets for ancillary services. In order to guarantee system security, the transmission system operator procures these services from market players amongst others active power reserves, reactive power delivery and black-start capabilities.

With increasing technical capabilities, it is expected that wind power can access these markets in order to procure additional revenues.

3.2 Techno-economic Barriers for Wind Power Integration

The second major contribution of the project is the identification of techno-economic barriers for integrating wind in the Belgian power system. Results are however not to be seen as negative advice towards wind power integration but to prepare industry and policy makers for necessary measures to achieve their targets in a responsible and cost-effective way. Studying these barriers is a first step towards presenting necessary measures to overcome them.

Techno-economic barriers are identified by means of a case-study of the current Belgian power system. This is modelled by means of a unit commitment and economic dispatch model where the generation park minimises costs to meet demand while facing technical constraints: ramping up rates of different power plants, fuel costs, network capacity, etc. Wind power is integrated by means of the capacity projections towards 2020, i.e. 4320 MW. Additionally, the modelled power system takes into account scheduled investments towards 2020.

3.2.1 Electricity Generation System

Simulation results show that the amount of wind power that can be incorporated in the system is not endless. Conventional power plants are characterised by certain operational and economic constraints. Therefore, their activation is planned on beforehand to meet expected demand at lowest cost facing ramping rates, start-up costs, minimal activation time, etc. This is referred to as unit commitment in which the on/off state and output level of every generator is planned. In real-time, the economic dispatch determines the generation level of each power plant to meet demand.

As already discussed, prediction errors require corrective actions in real-time which usually corresponds to increasing or decreasing the activation level of the generators or to start flexible generators. Availability of this flexible capacity is an important barrier of the generation system for wind power integration. In this study, the power system model includes 300 MW spinning reserves to cover imbalances. Additionally, peak power plants offer an additional reserve of 737 MW if not committed. Positive imbalances (overproduction) can be resolved by wind power curtailment (at a certain cost of renewable generation). If enabled, problems of prediction errors can be smoothed by import and export.

The model, representing the power system towards 2020, indicates that wind power variations and prediction errors cannot be balanced without wind power curtailment and/or import and export. This is explained by moments where net demand profile (demand minus renewable generation) is lower than the total installed nuclear capacity, which is equal to 5947 MW. Currently, nuclear power plants in Belgium are operated in a base load mode, since there is no need for modulation. This means they have a very low flexibility and are unable to follow demand variations. Knowing that there are also Combined Heat and Power plants (CHP) that must run during Summer (since these are industrial production profiles) with a maximum total output of 406 MW, a combination of those situations would lead to a problem.

A justified solution exists in allowing the nuclear power plants to operate in a load-following mode, an operation that will be more and more applied in future across Europe where massive wind injection is expected. More specifically, nuclear power plants can vary their power output between 60% and 100% of their rated capacity in 10′ (hence leaving 0.6*5947 = 3568.2 MW). This is implemented in the power system model in order to perform further simulations. Technical and economic feasibility of these adaptations of this solution in Belgium is not reviewed in detail and should be further investigated.

Even with the nuclear power plants modulating, results show periods where flexibility of the generation park is still not adequate to cover the largest wind power prediction errors. Therefore, export and import are implemented in the model. However, as the research focuses on the self-reliance, this solution is attached with a high cost (low export and high import price) so this would be used only as a last resort. In that view, export can be seen as an alternative for wind power curtailment and import as a need for additional reserves. In reality, import and export depends on generation costs in other countries and occur on the forward markets. In future, also international balancing markets may be created under the precondition of interconnection capacity.

Results show that import occurs in periods with large demand and overestimation of wind generation. Without the possibility of import, an overestimation of wind power generation may result in expensive measures to balance the system (demand curtailment or additional reserve requirements). On the other hand, situations with low demand and large underestimates of wind resources can create problems to absorb wind power. This may result in wind power curtailment or other expensive measures. Therefore, import and export are a useful tool to absorb additional wind power generation if the costs to accommodate additional wind energy are high.

3.2.2 Network Constraints

When expanding the electricity generation system with new capacity, additional network reinforcements may be required. This is certainly expected for high projections towards the installed capacity of wind power. Due to its variable character, wind power increases network flows and capacity problems may occur with high wind resources, generating at full capacity. Additionally, wind power is often located in remote areas increasing the demand for transmission capacity.

In the framework of this project, a preliminary analysis is performed to assess the capability of the network, including scheduled investments, to facilitate the 2020 projections of wind power capacity. This is done by means of a DC load flow model, being a simplified variant of a full AC load flow and generally used for techno-economic studies. When using the right assumptions, the error on the active power flows through the transmission lines can be limited to 5%. Exceptional errors on individual lines may however still occur. The main advantage of this technique is a limited simulation time.

By means of DC power flow simulations, it is concluded that the planned network towards 2020 will not be capable of facilitating 4320 MW wind power without overloading certain transmission lines. The capacity constraints of a number of transmission lines are too stringent for the increased power flows stemming from wind power. Results show that most problems are situated in the South-East of Belgium. In this area, the grid is less meshed. The second problem is close to the coast. The 2000 MW installed capacity of offshore wind power leads to overloaded lines. The most straightforward solution is to reinforce these lines. However, other solutions might present a valuable alternative, like dynamic line rating[18]. Consequently, the presented solution enables further analysis but requires an additional evaluation by using full power flow simulations.

Detailed analysis of network barriers solutions is out of the scope and difficult to assess by using only DC power flow. However, in order to maintain future power system reliability, it is highly recommended to perform detailed research of the impact on network operation of detailed future wind power projections including geographical location.

[18] Dynamic line rating is a technique that enables to load a line to the instantaneous capacity level. This level differs from the standard summer and winter rating. This level is frequently higher, especially in case of high wind due to the additional cooling effect.

3.3 Measures for Balancing Wind Power

In the framework of this project, four technologies are presented, attributed with flexible operation capabilities to offset wind power variability:

- large hydro storage and pumped hydro storage;
- dynamically controlled gas fired power plants;
- decentralised storage;
- demand response.

A. Hydro Storage

A water dam as large hydro storage facility is, given enough water supply, probably the best way to enable more wind power in a power system. A water dam is characterised with extremely rapid start-up and shut-down times, and can easily respond to changes in electricity supply and demand. Some plants can achieve a variation in power output of 100% which can be reached within one minute. This can be performed without significant effect on the lifetime of the equipment. Another benefit is the fact that the fuel cost of hydro-electric plants is zero, as is the greenhouse gases emission.

On the other hand, hydro-electric power plants require large investments and are bound to geographical constraints. Almost all hydro-electric potential is exploited in Europe and no opportunities for Belgium are present. However, their balancing capacity may become available from other countries (cfr. Norway).

Another hydro-electric solution which captures interesting balancing potential is pumped storage. With this technique, water is pumped up to a higher level. The potential energy stored in a reservoir, can be retrieved afterwards when this water is released and flows to the blades of a turbine. Up to now, this technology is assessed as the only economic way to store energy in large quantities and interesting for back-up purposes due to flexibility comparable with hydro-electric plants. No direct fuel costs or greenhouse gas emissions occur. Electricity is consumed reaching efficiencies between 70 and 85%.

Due to geographical constraints, its potential is again limited in Belgium. Two pumped storage plants are currently present in Belgium with a capacity of 1164 MW (Coo) and 224 MW (Plate Taille). They are both taken into account when modelling the Belgian power system. On the other hand, new innovative hydro storage concepts are currently under research e.g. offshore 'energy islands' pumping water out of a reservoir resulting in electricity generation when allowing the water to flow back.

B. Dynamically controlled gas-fired power plants

In the perspective of balancing wind power, flexible generation capacity can be provided by combined-cycle power plants (CCGT) or peak power plants. CCGT plants are based on a gas turbine followed by a steam turbine which uses the hot exhaust gases of the gas turbine as input. Literature states that the plant can be started between 40 - 150′ depending on the start-up temperature. The gas turbine of the CCGT plant is independent of the standstill time and is able to reach maximal power (two-third of the rated power of the CCGT) after 30′. Though, with a cold start, a more economic start-up is considered requiring 2 h. Shut down times of the power plant is much shorter: 14′. These power plants are characterised by a fuel cost and greenhouse gas emissions. On the other hand, high efficiencies of 50 - 60% are attained which decreases when deviating from full load. This technology is assessed as a viable solution for Belgium, where CCGT already counts for a substantial part of the power generation, i.e. 4700 MW.

In general there exist three types of real peak power plants: turbojets, gas turbines and diesel power plants. Turbojets are gas turbines, but instead of gas, they use petroleum as fuel. These three types of power plants are characterised by the fact that they can start up rapidly. They are by consequence used as peak-units, when demand is very high, or as emergency-units, when another plant unexpectedly fails to deliver power. However, these plants are characterised by low efficiencies between 20% and 40%. Peak power plants currently account for 708 MW in the Belgian power system.

Results show that adding additional CCGT power plants to the system will have no effect on the flexibility of the Belgian power system in balancing forecast errors, since most power plants have, on an one hour horizon, ramp rates in the same order as CCGT power plants. Only when looking at a time scale of 15′, CCGT power plants probably have more effect on flexibility. However, it has to be said that in the project model, also nuclear power plants can change their output within 10′ between 60% and 100% of their capacity (VGB PowerTech, 2010).

More effect of CCGT power plants are seen on CO_2 emissions, if fuel switching would occurs. However, taking fuel cost as projected by IEA, NEA and OECD (2010) leads to the result that coal would be less expensive than gas-fired power plants, even with a CO_2-tax of 30 €/ton CO_2 emitted. This results in a unit commitment schedule where coal-plants are scheduled before CCGT power plants, having as consequence no effect on CO_2 emissions. However, the coal price, as used by IEA, NEA and OECD, is quite low. Increasing this coal price would yield different results. Also a higher CO_2 price, which off course can be attained by 2020, could yield other results.

C. Decentralised Storage

Electricity storage has the potential to play an important role for improving the manageability, controllability, predictability and flexibility of the European power system. Therefore, storage technologies are expected to play a key role in supporting the integration of significant additional capacity of wind energy sources. On one hand, a dedicated energy storage device combined with a wind plant can shape wind power output, transforming the wind generation into a firm and predictable energy source, hence enabling wind generation to better exploit power market opportunities. On the other hand, energy storage systems, which have prompt response time and limited deployment time, offer additional measures of providing balancing capacity.

There is a quite wide range of electricity storage technologies available today or under development. In this project, an extensive overview of the basic principles and of the main technical characteristics of various storage technologies (power rating, typical discharge times, investment and operation costs, efficiency, response time and life time) are presented. Due to the lack of maturity of storage technologies and the fact that these technologies are not yet widely commercialised, results often disagree on the values of the technical characteristics. Consequently, the accessible domain of values provided in this report for each characteristic is sometimes very wide and must be used cautiously. The storage technologies best suited and more often recommended for supporting wind generation integration are identified. Four types of applications have been considered: primary frequency control (flywheels, batteries), spinning reserve, intra-day wind variability mitigation (batteries and flow batteries) and long term wind variability mitigation (pumped hydroelectric and compressed air energy storage).

In order to assess the impact of a technology in balancing future wind power variations, 150 MW of decentralised storage is added to the system towards 2020. Decentralised storage units are implemented in the same way as pumped hydro units, but with less installed capacity at their disposal. In total, 40 units are integrated in the Belgian system at 40 different nodes. Each unit can store an energy content of 7.5 MWh, and has a rated capacity of 3.75 MW. Results show limited impact probably due to the limited capacity compared to the power system. In order to draw sound conclusions, scenarios for decentralised storage have to be further improved.

D. Demand Response (DR)

Demand-side response is assessed as a future technology holding large potential for balancing wind power variations. It is based on a concept that by giving well-chosen incentives, demand can be managed to counteract expected and unexpected wind power variations.

In Belgium, a first rough calculation veils a potential of 358 MW available for DSR, only contracted from the most important domestic appliances. This number is based on a minimal level of acceptance by consumers. Potential increases significantly, up to 946 MW, in a scenario where all residential consumers participate in demand-side actions. Moreover, with possible integration of plug-in electric vehicles, the annual household consumption may double which results in an important future potential, both for storage and DSR. The calculated potential is only an average power demand. In order to obtain the demand available at each moment, specific demand profiles are to be taken into account. Technical and economic potentials of demand participation from residential consumers are currently studied in various national (cfr. LINEAR) and international projects (cfr. ADDRESS).

Benefits for balancing wind power are studied through the introduction in the power system model. It is modelled to offset real-time imbalances between demand and generation: during every hour, demand can be shifted with maximum 1000 MW, with the extra constraint that at the end of every day the balance of every pre-scheduled and postponed demand must be zero. Although this implementation of DR can be further refined, it enables to draw preliminary conclusions and trends on the effect of implementing large amounts of DR capacity.

Results show substantial reduction in the necessary activation of peak power plants and imports to balance wind power prediction errors. This is a good indication of DR being a tool prone to offset wind power variations having a positive effect on system reliability.

4. DISSEMINATION AND VALORISATION

4.1 Final Workshop

The WindBalance consortium organised a final workshop in Brussels, March 18, 2011. In this workshop, the project research partners presented a summary of the final results of the project. Among the participants are expected to be represented: industry, research institutes and policy makers. This allows a broad dissemination of this final report together with its conclusions and policy recommendations. Additionally, an interactive discussion round was organised, bringing together delegates from different background and industries, in order to discuss project conclusions and remarks from the workshop participants. This allowed the valorisation of the results.

The date is chosen strategically one day after the European Wind Energy Association conference which is this year organised in Brussels 11-17 March 2011. This allows to take into account the conclusions of the conference and the latest developments in the wind energy sector when discussing final results of the project. On the other hand, this facilitates the participation of key players in the industry enhancing dissemination and valorisation of the workshop.

The agenda of the workshop is subdivided into three major parts.

- Introduction: presentation of key findings of the EWEC conference (EWEA)
- Presentations: project results and conclusions (3E, K.U.Leuven)
- Interactive panel discussion (K.U.Leuven)

4.2 Journal Articles

A second key activity when valorising and disseminating project results is publication in internationally peer reviewed articles. Part of the work is already published in journals as:

- Renewable and Sustainable Energy Reviews
- Renewable Energy Journal
- IET Renewable Power Generation
- Energy Conversion and Management
- International Journal of Energy Research
- Applied Energy
- Energy Policy

Results including the final task of the project are not yet published. Therefore, the consortium plans to publish these during 2011 in an international peer-reviewed journal.

5. PUBLICATIONS

Articles in internationally reviewed scientific journals

- Luickx, P., Delarue, E., D'haeseleer, W., 2010. Impact of large amounts of wind power on the operation of an electricity generation system: Belgian case study. *Renewable and Sustainable Energy Reviews*, 14(7), 2019-2028.
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