Impact of Trading Arrangements on Imbalance Costs

Elforsk rapport 09:68

Mikael Amelin

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ELFORSK

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Preface

Demand Response is a mechanism designed to reduce load peaks. Load peaks are normally handled by maintaining production reserves that are activated when demand peaks, but this can be very expensive, and has led to considerable price volatility in the past. Demand Response, by which electricity consumers are induced to shift consumption from load peaks to load troughs by exposing them to spot price variations, has been seen as a cheaper way to handle peak load situations.

Demand Response has been available to large-scale electricity consumers for many years, but with the recent spread of AMM technology, even households can now be included in Demand Response programs.

Another factor behind the surge in interest for Demand Response are plans for large-scale deployments of wind power. Wind power is an intermittent source of energy, and massive use of wind power will most likely lead to increased price volatility. Demand Response can help reduce this volatility.

The current electricity trading arrangements in the Nordic region may have to be modified in order to accommodate large-scale use of wind power and Demand Response programs. This report describes a study of the properties of the electricity trading arrangements that are important for an efficiently functioning electricity market in the presence of large-scale use of wind power and Demand Response. The study has been carried out as a set of simulations where a new model has been applied to a number of fictitious markets that resemble the electricity markets in the Nordic region.

Elforsk (Electricity research) is owned by the Swedish electricity industry. Its corporate business idea is to carry out research and development in line with the interests of the owner companies and carry out these research projects in cooperation with other parties on the market. The Market Design program was initiated in 2000 for the purpose of increasing the knowledge of how deregulated electricity markets work. The program is financed by Svensk Energi, EBL-Kompetanse in Norway and the Swedish Energy Agency.

More information on the program, our reports and current activities is available on program's website, www.marketdesign.se.

Stockholm, June 2009

Peter Fritz
Program Secretary, Market Design
Elforsk AB

Sammanfattning

Det finns idag planer på en storskalig utbyggnad av vindkraften i både Sverige och i grannländerna. Samtidigt finns det utveckling mot ökad priskänslighet hos konsumenterna. Dessa två förändringar är delvis kopplade till varandra, eftersom större volymer vindkraft medför ökade prisvariationer både på spotmarknaden och på reglermarknaden, vilket gör det önskvärt med konsumenterna som i högre grad är aktiva på elmarknaden.

I den här rapporten studeras olika aspekter av regelverket för elhandeln, som har betydelse för hur effektivt en elmarknad med stora volymer vindkraft och ökad förbrukningsflexibilitet fungerar. Studien bygger på en ny simuleringsmodell, som beräknar priset i de olika faserna i elhandeln givet utbuds- och efterfrågekurvor baserade på de prognoser som finns tillgängliga vid varje tillfälle. Denna modell har sedan tillämpats på ett antal testsystem, som förvisso är fiktiva, men vars grundläggande egenskaper påminner om de förhållanden som man kan hitta på den nordiska elmarknaden.

Följande aspekter av elmarknadens utformning har studerats:

- **Planeringshorisont.** Med planeringshorisonten avses väntetiden från att aktörerna lämnat bud till spotmarknaden fram till själva leveranstimmen. Konsekvensen av att förkorta planeringshorisonten är att man för mindre prognosfel, i synnerhet när det gäller vindkraftprognoser. Resultaten från fallstudien visar att en kortare planeringshorisont har ett värde för de flesta aktörer på elmarknaden. Om en sådan förändring av elmarknaden är lönsam beror emellertid på om värdet av de förbättrade prognoserna är större än de administrativa kostnaderna.

- **Prissättning av balanskraft för vindkraft.** Idag tillämpas tvåprisavräkning för produktion och enprisavräkning för konsumtion på den nordiska elmarknaden. Ett alternativ vore att betrakta vindkraft som negativ förbrukning och räkna in vindkraftens obalanser i de balansansvariga aktörernas konsumtionsobalanser. Detta skulle medföra minskade obalanskostnader för vindkraftsägare, men resultaten från fallstudien visar att skillnaderna är små jämfört med att behandla vindkraft som övrig produktion. Förklaringen till detta är att obalanskostnaderna trots allt endast utgör några procent av vindkraftsägarnas intäkter från såld el.

- **Ökad förbrukningsflexibilitet.** I den här rapporten studeras konsekvenserna av att införa en typ av kontrakt, som gör det möjligt för elleverantören att under ett begränsat antal timmar per år initiera lastminskningar hos vissa konsumenter. I fallstudien visade sig denna typ av kontrakt vara gynnsamma för samtliga aktörer (även sådana som inte själva var balansansvariga för någon konsumtion). Den ökade förbrukningsflexibiliteten ledde också till en ökad leveranssäkerhet i de studerade systemen. Dessa fördelar måste naturligtvis vägas mot kostnaderna för att introducera sådana kontrakt och för den nödvändiga infrastrukturen.

Summary

Today there are plans for large wind power investments in Sweden as well as in the neighbouring countries. At the same time, there is a development towards increased price sensitivity of the consumers. These two changes are partially connected to each other, because larger volumes wind power will result in increased price variations in the spot market as well as the real-time balancing market, which makes it desirable with consumers who are more active in the electricity market.

This report studies different factors of the electricity trading arrangements, which are of importance to the efficiency of an electricity market with large volumes of wind power and increased consumption flexibility. The study is based on a new simulation model, which calculates the price for the different phases of the electricity trading using supply and demand curves based on the forecasts that are available in each phase. This model has then been applied to a number of test systems, which although fictitious, have the same basic characteristics as the conditions found in the Nordic electricity market.

The following factors of the design of the electricity market have been studied:

- **Planning horizon.** The planning horizon refers to the delay time from when the players have to submit bids to the spot market until the actual delivery hour. The consequence of shortening the planning horizon is that the forecast errors will be smaller, especially for wind power forecasts. The results from the case study show that a shorter planning horizon is beneficial to almost all players in the electricity market. If such a change of the electricity market is profitable does however depend on whether the value of the improved forecasts is larger than the administrative costs.

- **Pricing of wind power imbalances.** In the present Nordic electricity market, a two-price system is used for generation and a one-price system is used for consumption. An alternative would be to consider wind power as negative load and include wind power imbalances in the consumption imbalance of the balance responsible players. This would result in decreased imbalance costs for wind power producers, but the results from the case study show that the differences are small compared to treating wind power as other generation. The explanation to this is that the imbalance costs in spite of all are only a few per cent of the wind power producer' income of selling electricity.

- **Increased consumption flexibility.** This reports considers the consequences of introducing a new form contracts, which allows the retailers to initiate load reductions for certain consumers during a limited number of hours per year. In the case study, this kind of contracts turned out to be beneficial to all players (including those who were not themselves balance responsible for any consumption). The increased consumption flexibility also resulted in improved reliability of supply. These advantages must of course be compared to the costs of introducing such contracts and the necessary infrastructure.

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1 Introduction

Electric energy cannot be traded without a technical infrastructure; there has to be a grid connecting producers and consumers and there has to be automatic control systems that guarantee safe operation of the grid. Besides the technical infrastructure, there will also be a need for a trading infrastructure, which defines how the players should pay for common resources such as the grid and its control systems, as well as a procedure for accounting of who is selling electric energy to whom. However, there is no natural and fair way of defining the rules for electricity trading. Since all players have slightly different conditions, a given set of rules will be more advantageous for some players than for others. The legislator will have to choose a trading framework that promotes the development of the electricity trading and the power system, which is the most beneficial to the society.

The design of an electricity market has to cover a wide range of aspects. This report will focus on two specific questions, namely how long time before the time of delivery that electric energy should be traded, and how the inevitable imbalances due to forecast errors should be priced. Special attention will be given to how these issues affect the profitability of wind power and consumption flexibility.

1.1 Background

Both wind power and consumer flexibility has received a lot of attention the recent years. The concern of climate changes due to global warming have prompted many countries to set up ambitious plans to increase the amount of renewable electricity generation, and wind power is often an important part of these plans. The Swedish Energy Agency has proposed a Swedish "planning target" of 30 TWh wind energy per year in 2020 [3]. Already today, Denmark generates about 20% of its electricity (7 TWh out of the total generation of 37 TWh) from wind power [1].

A disadvantage for wind power producers compared to conventional power sources is that the generation is depending on the weather; hence, wind power generation is difficult to forecast more than a few hours ahead. Shortening the time interval between the market closure and the delivery (which today is between 12 and 36 hours in the Nord Pool Elspot market) would therefore allow wind power producers to submit more accurate bids, which should increase the profits of electricity sales for wind power producers. More accurate wind power forecasts would also reduce the need for the system operator to activate up- or down-regulation, which should reduce the regulation fees. However, reducing the delay time could also result in additional costs for the players of the electricity market, for example due to an increased need to keep staff on duty during mornings, evenings and nights.

Since the restructuring of the Swedish electricity market in 1996, the trend has been that the consumption has continued to increase, whereas not much new capacity has been added—in fact, several peak capacity units have been shut down since they have not been profitable. A similar development has been observed in the other Nordic countries and many other restructured electricity markets around the world. Consequently, it has been feared that problems with power deficit will be more frequent in the future.

One way to counter this development would be to increase the peak capacity of the system, for example using capacity credits (as in several markets in North America) or by making the system operator responsible that there is extra peak capacity, which is bid to the market at a predetermined price (as the Swedish power reserve). However, it is unavoidable that the total generation cost (i.e., fixed costs divided by the annual energy generation in MWh plus the variable costs) will be quite high for a peak capacity unit that is only used for a very limited number of hours per year. Therefore, it has been suggested that it better to promote consumer flexibility, i.e., to encourage consumers to respond to high electricity prices by reducing their consumption.

Flexible consumers will not only reduce the need for peak capacity units, but could also have a dampening effect on price spikes which have been observed in many restructured electricity markets, and which are expected to become more frequent in electricity markets where there is large amounts of wind power. Reducing the size and frequency of price spikes would be beneficial to many retailers, as it is common that retailers buy electricity at a variable price in the spot market but sell the electricity to the final consumer at a fixed price. One way to improve the flexibility of the consumption is to introduce new contracts, which allow the retailer to activate load reductions for a shorter period (typically one or a few hours). The number of hours per year that the load reduction can be activated might be restricted. As compensation, the consumer receives a slightly lower fixed price. The experience of Swedish field tests with such contracts have been described in [9], [10].

1.2 Problem Statement

The main topics to be studied in this report is shortening the time interval between market closure and delivery, changing the imbalance pricing system and the impact of introducing more flexible consumption. The data that is needed to study these issues is basically the imbalances of different players and the prices used to settle the imbalances.

One approach is therefore to simply collect historical series of these data. In [11] historical data from Denmark were used to investigate the consequences of different trading arrangements for wind power producers. A similar approach has also been used in [7]. An alternative is to use historical data to define random variables or stochastic processes that can generate values of imbalances, spot prices, real-time balancing market prices, etc. with appropriate correlations, as for example in [8]. It is also possible to use stochastic process for this kind of modeling [12]. An advantage of the stochastic method compared to using historical data is that the stochastic process will also generate values that have not yet been observed in reality, but which have a certain probability of appearing in the future.

However, regardless of whether the historical data is used directly or as a basis for a probabilistic model, a disadvantage of these methods is that they are only valid in the same context as the data was collected. For example, if data are available for an existing system with a small amount of wind power and inflexible consumption, and the aim of a study is to determine which trading arrangement is optimal for a future system with large amounts of wind power and a significant share of flexible consumers, then historical prices will be less useful, as it must be expected that both spot prices and imbalance prices change when new generation resources are added and consumers change their behaviour during high price periods. Hence, relations that were observed in the old system may provide misleading results if used also in the future system.

Models based on historical data can be seen as price models, in the sense that the focus of the modelling is the prices themselves. Another way to generate imbalances and prices is to use an electricity market model that explicitly simulates the different phases of electricity trading, and there prices are given by supply and demand according to the available forecasts in the corresponding phase. As mentioned above, price models have already been applied to study the impact of trading arrangements on wind power producers. Therefore, this report will try to provide further insights on the topic by introducing an electricity market model.

1.3 Objective

The objective of this work is to investigate how the players of an electricity market are affected by different trading arrangements in an electricity market with large amounts of wind power and flexible consumers. The investigation will be based on an electricity market model developed specifically for studies of trading arrangements. The following properties of the electricity market must be explicitly modeled:

- **Delay time between bids and delivery.** The shorter the delay, the better forecasts will be available; hence, the imbalance costs will be reduced.
- **Imbalance pricing.** The pricing of imbalances will of course be important for those players who cannot avoid significant forecast errors, as some imbalance pricing schemes are more forgiving in the long run, which will also reduce imbalance costs.
- **Flexible consumers.** If high prices are forecasted, some consumers are able to reduce their consumption. This will decrease some price peaks, which otherwise would have affected both spot prices and imbalance prices.

The model will be applied to a set of test systems. Due to lack of public data, the test systems to be studied will have to be fictitious, but they should yet have properties similar to those of the Nordic electricity market. The players to be studied should include for example small wind power producers, power companies with small or large generation resources and retailers.

The results will give an indication on the relative importance of different trading arrangements.

2 Electricity Trading

A fundamental property of electric energy is that it cannot be stored; it has to be generated at the very same moment that it is consumed. Hence, the electric power input to a power system must always equal the electric power output. The only practical way to maintain this balance is to use automatic control systems. Whenever a consumer is increasing his or her consumption, the control system will make sure that some generators increase their generation by the same amount. This means that the consumer is buying energy in real-time from several generators. Since these kinds of transactions occur continuously, it would be an impossible task to keep track of all trading that occurs in real-time. Consequently, electricity trading is not performed in real-time—electricity is traded is divided in certain time periods, which in this report will be referred to as *trading periods*. The trading period in the Nordic power system is one hour, which is also a common choice in many other electricity markets, although there are also some electricity markets that use shorter trading periods.

The introduction of trading periods results in a division of the electricity trading in different phases: before, during and after a specific trading period. This chapter will provide a general overview of these phases. The chapter also describes important concepts that will be used in the modelling and case studies (chapters 3 and 4 respectively).

2.1 Ahead Trading

The ahead market refers to all contracts which are signed before the actual trading period; hence, it includes both contracts of physical delivery and financial derivatives. This study will only focus on the trading of physical contracts, i.e., contracts that are reported to the system operator and accounted for in the post trading phase.

The trading of physical contracts can be organised in many different ways; an electricity market may have several market places for ahead trading, each with different time frames and different types of contracts. However, two main categories can be identified: trading through a power pool and bilateral trading. These alternatives will be discussed below.

Power Pools

Players who want to trade in a power pool submit purchase and sell bids respectively. These bids can be designed in different ways. The simplest form of a purchase bid is to specify the highest price that the player is willing to pay for a certain amount of electric energy during a certain trading period. In a similar manner, a simple sell bid specifies the least price for which the player is willing to sell a certain amount of electric energy during a certain trading period. Hence, the common purchase and sell bids are valid for one particular trading period. It is also possible to allow bids that are valid for several trading periods. Such bids are called block bids and must be accepted as a whole. If a player submits a purchase block for 1 000 MWh/h during 5 hours if the price is at most 20 ¤/MWh, then this bid will only be accepted if the average electricity price during all five hours does not exceed 20 ¤/MWh.

Also the principle for how the electricity price is calculated may differ between different power pools. The most common arrangement is a power pool with a price cross. In such power pools the sell bids are arranged to a supply curve, by sorting the sell bids in ascending order according to the requested least price. The purchase bids are arranged to a demand curve in a similar manner, by sorting the purchase bids according to descending willingness to pay. The electricity price is then determined by the price cross, i.e., the intersections between the two curves (see Figure 1). All bids to the left of the price cross are accepted and they all receive the same electricity price. Thus, all purchase bids where the highest price is higher than the electricity price given for the trading period are accepted, as well as all sell bids where the least price is lesser than the electricity price. Notice that most players receive a price which is more beneficial than the price they were willing to pay and sell for respectively.

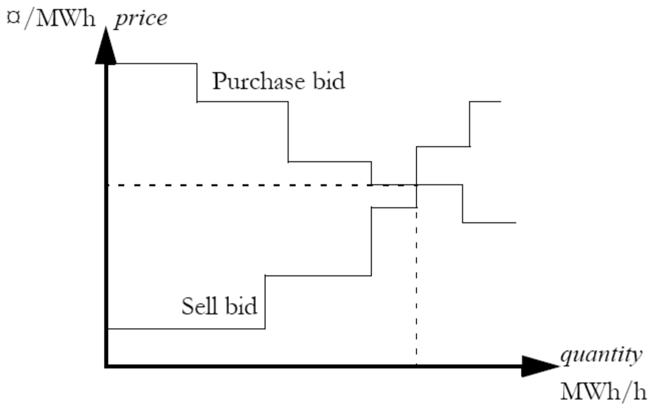

Figure 1 *Pricniple of power pool with a price cross.*

Another variant is to have a separate price for each transaction. The power pool lists all submitted bids and if a player finds the price appealing they can accept the bid.

Some power pools (for example the Nord Pool Elspot market) have a limitation to how much may be traded between different parts of the grid. In this case the grid is divided in price areas. When a player submits a bid to the power pool, they have to specify the price area in which energy will be injected or extracted as well as the usual quantity, price and trading period. If the trading between two areas should exceed the stipulated limitation, then the market is split in multiple parts with individual electricity prices for each part.

Bilateral Trading

By bilateral trading we refer to all agreements which are made directly by two players. The bilateral trading must be reported to the system operator, as it is to be accounted for in the balances of the post trading market. Several kinds of contracts are used for bilateral trading. The two most common types of contracts are firm power contracts and take-and-pay contracts. Firm power means that a given constant power is traded during a given time period. This sort of contract is usually used to cover the base load. Take-and-pay contracts mean that the buyer can consume as much as he or she wants, up to a certain limit. This type of contract is for example used by regular residential consumers; in this case the power limit is set by the size of the main fuse.

A bilateral contract also states the electricity price paid by the buyer. The price can either be the same for the entire duration of the contract (fixed price) or changing over time (variable price). A variable price can for example be determined by the electricity price at a power exchange plus a certain uplift.

It can be noted that with the exception of a firm power contract with fixed price, a bilateral contract will result in some uncertainty. A consumer who is buying electricity at a variable price will not know the price in advance and a producer who is selling electricity in a take-and-pay contract will not know the exact sales until after the end of the trading period.

2.2 Real-time Trading

The real-time market includes the trading which occurs during a trading period. A real-time market is needed for several reasons. During the delivery period, players are supposed to follow the resulting plans from the ahead market. However, deviations from the plans are inevitable, due to forecast errors. Smaller deviations are managed by automatic control systems (primary control and automatic generation control). Moreover, the trading in the ahead market may not have taken into account the physical limitations of the grid, which may force the system operator to redispatch production or consumption in order to maintain safe operation of the grid.

There are two ways of organizing the real-time trading. The first variant is to establish a real-time balancing market, which means that the players normally decide themselves how much to produce or consume, but if necessary the system operator asks a certain player to change the production or consumption. The second variant is that the system is centrally dispatched by the system operator and the other players are obligated to follow the instructions of the system operator.

The Nordic system operators run a joint real-time balancing market for the Nordel synchronous grid. Players with dispatchable resources can submit two kinds of bids to the real-time balancing market. Down-regulation bids means that the player is willing to reduce the power input to the system; thus, a producer carries out down-regulation by reducing the generation, whereas a consumer carries out down-regulation by increasing the load. Hence, down-regulation means that the player buys energy from the system operator and a down-regulation bid must therefore state how much the player can down-regulate (in MW) and the maximal price (in ¤/MWh) which the player is willing to pay for the purchased energy. Similarly, up-regulation means that the player sells energy to the system operator, i.e., an up-regulation bid states how much the player can up-regulate and the minimum price for which the player is willing to sell regulating power. Unlike the bids to the ahead market, regulation bids are not just a financial undertaking, but a physical commitment to change the power balance of the system—the system operator measures generation and load and may control that activated bids really have been carried out within time.

The pricing of the real-time balancing market can either be different for each activated bid or there may be uniform prices for up- and down-regulation respectively. Separate pricing means that those players buying regulating power pay exactly the price they stated in their down-regulation bid and the players selling regulating power get paid as much as they stated in their up-regulation bids. Using this pricing scheme the players will—provided that the competition is good—not be able to make any profits from the real-time trading; for example, a producer will buy regulating power at the same price as it would have cost to produce it and will when selling receive just as much to cover the production cost. Such arrangements are not very attractive neither for producers nor consumers; it implies that they submit bids out of public duty or that they are simply forced to submit bids whenever possible. To make a real-time balancing market more appealing it is possible to use marginal pricing instead, which means that a down-regulation price is defined, which is equal to the lowest price among the activated down-regulation bids, and an up-regulation price, which is equal to the highest price among the activated up-regulation bids. All activated bids will then obtain these regulating prices.

The pricing in the Nordic real-time balancing market is based on a combination of the above mentioned pricing schemes. Generally, all activated bids will receive the uniform down- and up-regulation prices respectively. However, if a bid is activated for grid reasons, i.e., as part of counter trading, the bid will not affect the down- or up-regulation prices, but will receive a separate price which is either equal to the price in the bid or the regular down- and up-regulation price (whichever is the most favourable).

2.3 Post Market

When a trading period is ended the system operator can compile how much the clients of a balance responsible player have actually produced and consumed, as well as how much they have bought or sold in the ahead and real-time markets. This will almost certainly result in a deviation between supplied and extracted energy. The purpose of the post trading is to settle these deviations. All balance responsible players having an imbalance have to trade in the post market in order to achieve balance. Players having positive imbalances (i.e., they have supplied more energy than they have extracted) sell imbalance power to the system operator. If there is a negative imbalance instead then the player has to buy imbalance power from the system operator.

The imbalance of a balance responsible player can be calculated in different ways. One way is to simply calculate a total balance of each player, i.e.,

$$\begin{aligned} \textit{total balance} &= \textit{measured generation} + \textit{reported purchase} \\ &\quad - \textit{measured consumption} - \textit{reported sales}. \end{aligned}$$

An alternative approach is to have separate imbalances for generation and consumption, i.e.,

$$\textit{generation balance} = \textit{measured generation} - \textit{reported sales}.$$

consumption balance = reported purchase – measured consumption.

The price of the imbalance power is generally related to the prices used during the real-time trading. The main difference is whether average or marginal pricing is used, and if the system operator applies the same or different prices for buying and selling imbalance power respectively. In this presentation, it will be assumed that marginal pricing is used (i.e., that the highest price of the activated up-regulation bids will set the up-regulation price, and that the lowest price of the activated down-regulation bids will set the down-regulation price), and the focus will be on the pricing of positive and negative imbalances.

The price is going to depend on whether the trading period is considered as an up-regulation period or a down-regulation period. If only up-regulation bids have been activated during the trading period then it is considered to be an up-regulation period. Similarly, if only down-regulation is activated then it is a down-regulation period. In those cases then both up- and down-regulation has been activated, it is the net regulation (in MWh) that will decide whether it is an up- or down-regulation period.

In a one-price system, the same price will be used for positive and negative imbalances. During up-regulation periods the imbalance price will equal the up-regulation price, whereas during down-regulation periods it will equal the down-regulation price. If the period is neither an up-regulation period nor a down-regulation period (i.e., if no bids at all were activated in the real-time trading) then the price will equal a reference price from the ahead market.[1]

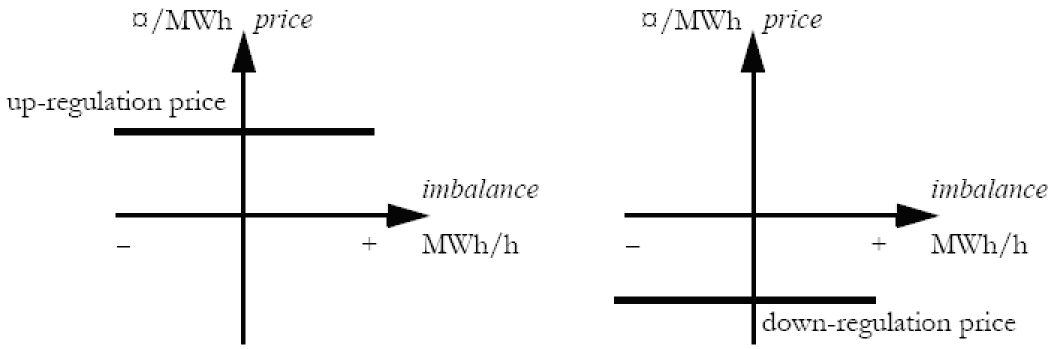

Figure 2 *One-price system for imbalance pricing during an up-regulation period (left panel) and down-regulation period (right panel) respectively.*

In a two-price system, there will be one price for negative imbalances and another price for positive imbalances. During an up-regulation period, players with a positive imbalance will sell their surplus for the reference price, whereas those who have a negative imbalance pay the up-regulation price. During a down-regulation period, players with a positive balance will sell their surplus for the down-regulation price, whereas those who have a negative imbalance will pay the reference price.

[1] For example, in the Nordic electricity market the price of the Nord Pool Elspot market is used as reference price.

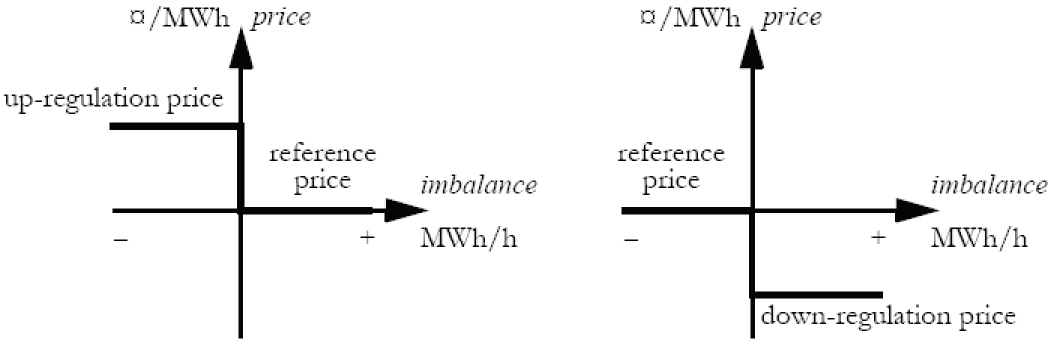

Figure 3 *Two-price system for imbalance pricing during an up-regulation period (left panel) and down-regulation period (right panel) respectively.*

The main difference between a one-price system and a two-price system is that a one-price system is more forgiving towards forecast errors. If the forecast error is helping the system—for example if a player is generating more than planned during an up-regulation period and therefore reduces the system operator's need to activate up-regulation bids—the player will sell the surplus to the up-regulation price, which is higher than the reference price. Hence, in the one-price system, players will occasionally receive a more favourable price compared to if the surplus or deficit had been known in advance and traded in the ahead market. In a two-price system, players who help the system will receive the reference price.

It can be noted that it is possible to combine one-price systems and two-price systems in the post trading. For example, in the Nordic electricity market a two-price system is applied to the generation balance and a one-price system on the consumption balance. It can also be mentioned that there are also other variants of imbalance pricing than the one-price system or two-price system. For example, it is possible to have mixed price system. As in the two-price system, there is one price for positive imbalances and one for negative imbalances. However, players who help the system receive a price that is somewhere between the up- or down regulation price and the reference price. Hence, these players receives a price that is favourable compared to the ahead market price, but not as favourable as in a one-price system. Another variant is to introduce a dead-band, which means that small deviations in the wrong direction are not punished by the unfavourable up- or down-regulation price (see Figure 5).

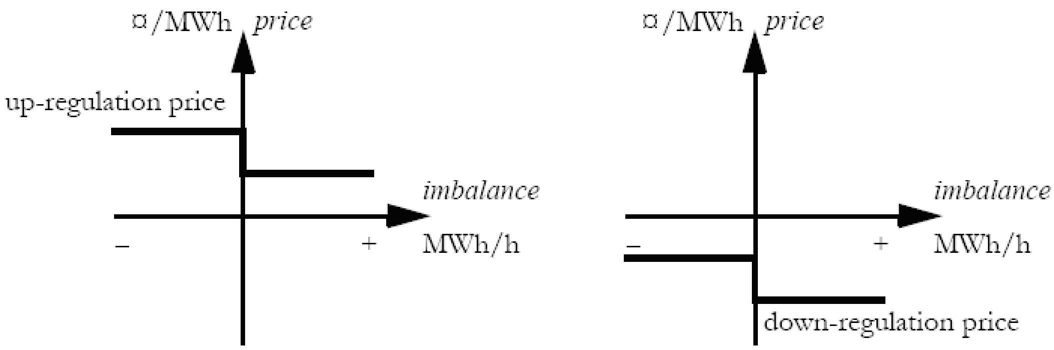

Figure 4 *Mixed-price system for imbalance pricing during an up-regulation period (left panel) and down-regulation period (right panel) respectively.*

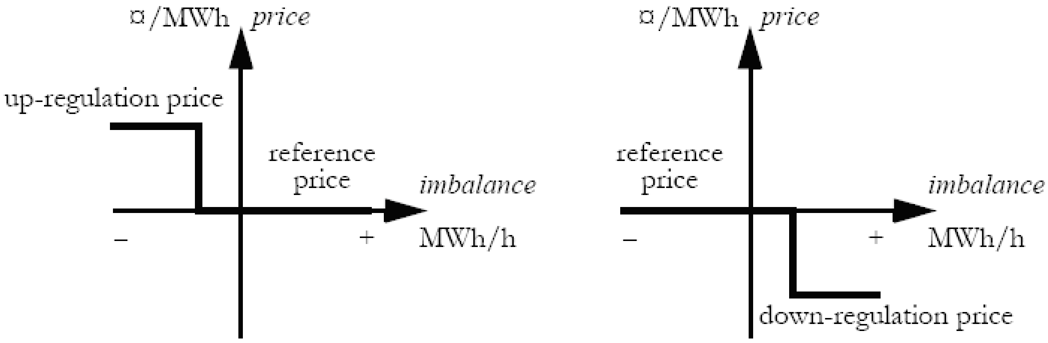

Figure 5 *Two-price system with deadband for imbalance pricing during an up-regulation period (left panel) and down-regulation period (right panel) respectively.*

However, the imbalance prices do not have to be set by the real-time market price. For example, the Swedish system operator applies an artificial price for negative imbalance in case of power deficit. This means that if load shedding has occurred, balance responsible players with a negative imbalance will not pay the up-regulation price, but a predetermined price (20 000 SEK/MWh according to [2]) unless the up-regulation price is higher than that.

In addition to the prices for selling and buying imbalance power, the system operator may charge an imbalance fee for each MWh of imbalance (regardless of whether it is a positive imbalance or negative imbalance). The imbalance fee may differ depending on the imbalance, so that for example one fee is applied to generation imbalance and another to consumption imbalance, etc.

3 Trading Arrangement Model

This chapter presents a simulation model that can be used to study the impact of different trading arrangements. The chapter starts with an overview of the model, followed by a short summary of the Monte Carlo simulation technique that is used. Finally, a detailed mathematical description of the model is given.

3.1 Model Overview

The general idea of the model is to model the different phases of electricity trading, by determining supply and demand curve based on the forecasts available at each phase. This section starts by describing main assumptions about time and players in the model, and then provides details about the modelling of generation and demand.

3.1.1 Time

As described in the previous chapter, trading of electric energy can be divided in a number of phases, before, during and after a specific trading period. This time-line of electricity trading will be explicitly included in the model presented here. However, the model will not include possible links between different trading periods—in reality, the generation level in a power plant during one trading period can set constraints for the possible generation in the next trading period. Including such time links between trading periods would significantly increase the complexity of the model,[2] and that does not seem justified for this kind of study.

The simulation of a specific trading period is divided in a number of ahead trading phases and real-time trading phases. The number of phases is arbitrary both for ahead trading and real-time trading. The ahead trading can for example be divided in a spot market phase and an adjustment market phase. The real-time trading can be divided in several phases to reflect the fact that the real outcome can be varying during a trading period—sometimes the wind power generation is higher than forecasted and sometimes it is lower, etc. By dividing the real-time trading in several phases, it becomes possible to simulate that both up-regulation and down-regulation can be necessary in the same trading period. This possibility is lost if only one real-time phase is used per trading period.

3.1.2 Balance Responsible Players

All producers and consumers must have an agreement with a balance responsible player, who will take the financial responsibility for balancing the trading of the clients. In the model, it is assumed that the balance responsible

[2] Examples of the difference between models considering a single time step and multiple time steps can be found in [1].

players have complete control over the dispatchable generation (i.e., the clients that own the generation will operate according to the requests of the balance responsible player), and that it is the balance responsible players that submit bids to both ahead and real-time markets.

3.1.3 Dispatchable Generating Units

The available generation capacity in a dispatchable generating is only depending on the state of the power plant, i.e., whether it is available or unavailable. As long as the unit is available, the producer can choose to generate as much as desirable between the minimal generation capacity and the installed capacity of the unit. Most conventional generation technologies, such as hydro power plants with reservoirs and thermal units, belong to this group.

The following subsections will describe the properties of dispatchable generating units which are included in the model.

Operation cost

The operation costs of a dispatchable unit are divided in variable generation cost and redispatch costs. It is assumed that bids to the ahead markets are based on the variable generation costs. For thermal units, the variable costs reflect the fuel consumption to generate one MWh of electric energy. For hydro units, the generation cost is very low. However, as hydro generation can displace thermal generation, each MWh of potential hydro generation has has an alternative cost, which is equal to the generation cost of the most expensive thermal power plant that can be displaced by the hydro power. This alternative cost is referred to as the *water value*. In reality, the water value depends on a large number of factors, for example inflow to the reservoirs, electricity consumption, generation costs in thermal power plants, etc. Hydro power producers use various planning tools to estimate the water value, and will then use the water value as bid price when selling hydro power. In this model it is assumed that the water values of all hydro power plants are known, and that hydro power can be considered as a thermal power plant with a variable generation cost equal to the water value. This is of course a huge simplification, but it is necessary if the model should not have to consider the links between different time periods; hence, it will be left to future studies to further develop the hydro modelling—in this report, assumed water values will be sufficient to create realistic prices in the fictitious systems studied in chapter 4.

A unit which is participating in the real-time balancing market will be subject to costs caused by the need to quickly change the planned generation of the unit. These costs might be due to start-up costs or losses (for example, water might have to be spilled if a hydro power plant is reducing its generation while the reservoir is full). Bids to the real-time balancing market will therefore be modified by a redispatch cost. It is assumed that the price in up-regulation bids will be equal to the variable operation cost plus an up-regulation cost, and that the price in down-regulation bids will be equal to the variable operation cost minus a down-regulation cost. It can be noted that the up-regulation cost and down-regulation cost do not have to be the same.

Available Generation Capacity

It is assumed that dispatchable units are either available or unavailable; hence, the available generation capacity of these units is a two-state random variable, the probability distribution of which is determined by the availability of the unit. However, in this model it will not be sufficient to know the state of the units during the trading period, but it will also be necessary to know the forecast that the producer used as basis their bids to the ahead market. These forecasts will of course be correlated to the actual state of the unit, which means that the forecasts and the actual state have to be randomised from a joint probability distribution.

The probability distribution of forecasts and real outcome for a dispatchable unit will be a discrete probability distribution. The number of states depends on the number of forecasts that are used in the model and the number of periods that the real-time trading is divided in. An example of a state space is given in Table 1. The probability of each state should preferably be determined from historical records. A persistence forecast can be assumed if there are no historical data available. A persistence forecast means that if the unit is available at the time of the forecast then the producer will assume that the unit will be available during the trading period in question; similarly, if the unit is unavailable at the time of the forecast then the producer will assume that the unit will be unavailable. This forecast technique justified for available units—it is not likely that producers would be able to predict the time for failures—but might be a little bit pessimistic concerning unavailable units, since the producer may very well have some information about how long time it will take before the unit is repaired.

Table 1 *Example of available generation capacity model for a dispatchable generating unit.*

Initial forecast	Updated forecast	Real outcome
Available	Available	Available
Unavailable	Available	Available
Available	Unavailable	Available
Unavailable	Unavailable	Available
Available	Available	Unavailable
Unavailable	Available	Unavailable
Available	Unavailable	Unavailable
Unavailable	Unavailable	Unavailable

Frequency Control Reserve

A power system must have automatic control systems to maintain the instantaneous balance between generation and load. These control systems are referred to as frequency control and is an essential part of a power system. The system operator pays producers for the provision of capacity for frequency control. The capacity payments are however not considered in the model and it is just assumed that each generating unit has a certain frequency control reserve. The reserve must be available for both up-regulation and down-regulation during the trading period, and units which provide frequency control reserve must therefore withhold part of their generation capacity from the ahead market. To be able to down-regulate, the frequency control units must be scheduled to generate some power during the trading period. In the model, this can be achieved by assigning a low price in the ahead market bids for these units, making it very likely that they are dispatched.

3.1.4 Non-dispatchable Generating Units

The available generation capacity of non-dispatchable power plants is not only depending on the technical state of the power plant (available or unavailable) but also on some outside factor. Wind power is a typical example of non-dispatchable units, since the available generation capacity depends on the wind speed at the site of the power plant. Other examples are photovoltaics (where the generation capacity depends on the insolation) and hydro power without reservoirs (where the generation capacity depends on the water flow passing the power plant).

Describing these power plants as "non-dispatchable" might give a slightly misleading impression; it is of course possible to dispatch the generation of these units by spilling power from time to time. However, this is never done in reality except for extreme situations, where the safe operation of the power system is in danger. The reason is that non-dispatchable units are characterised by high investment costs and very low variable operation costs. Hence, to be as profitable as possible, these units should always generate as much as they can. If the generation in the system needs to be decreased, it is preferable to do so in a power plant with higher variable operation costs, or in a power plant with low operation costs but with storage capability (for example hydro power with reservoirs).

The only non-dispatchable power source that will be considered in this report is wind power. The following subsections will describe the properties of wind power plants which are included in the model.

Operation Costs
The main costs of wind power are the investment costs, and the maintenance costs. Both of these costs can be considered as fixed annual costs. The variable costs of wind power can be considered negligible. Wind power plants cannot participate in the real-time balancing market; thus, up-regulation and down regulation costs are not applicable.

Available Generation Capacity
As for dispatchable units, there will be a need to randomise forecasts and actual outcome. The available generation capacity of a wind power is however not depending on just the technical state of the turbine, but also on the current wind speed. Therefore, in forecasts as well as the real outcome, the available generation capacity will be a continuous random variable distributed between 0 and 100% of the installed capacity of the turbine.

Generating correlated random numbers from a continuous probability distribution is a challenge, unless the random variables are normally distributed, which is not likely to be the case for wind power generation. In this report, an approximate method will be used. The main idea of this method is to divide the available generation capacity in a discrete part and a continuous part. The available wind capacity at a certain time step is then given by

$$\overline{W}_t = \overline{W}_t^D + \overline{W}_t^C. \tag{1}$$

The correlation between different forecasts and the actual outcome is represented by the probability distribution of the discrete part, $\overline{W}_t^D$. This probability distribution has K discrete states for each time period. These discrete states are found by dividing the installed capacity in of the wind units in K intervals, and the discrete states are then set at the centre of each interval. For $K = 2$ there would be one interval between 0 and 50% of installed capacity and another between 50 and 100% of installed capacity. The centre of these two intervals would be 25% and 75% of installed capacity respectively. If the wind power model includes two forecasts and the real outcome then there would be eight possible states for the distribution of $\overline{W}_t^D$. These states are listed in Table 2. The probability of each state in these multivariate distribution would be difficult to estimate from a theoretical model, and the only practical solution is to obtain these probabilities from historical data records of forecasts and associated forecast errors.

The continuous part, $\overline{W}_t^C$, is generated by independent uniform distributions for each time step. The minimum value of the uniform distribution is $-\hat{W}/2K$ (where $\hat{W}$ is the installed capacity and K is the number of discrete states in $\overline{W}_t^D$) and the maximum value is $+\hat{W}/2K$. In for example the case where $K = 2$, each uniform distribution would be between −25% and +25% of the installed capacity.

Using this model, it is possible to introduce various degrees of correlation between different wind farms in a system. For example, if a separate random values of both the discrete and continuous parts are generated for each wind farm, then the available generation capacity of each wind farm will be independent from all other wind farms. However, if the same discrete part is used for all wind farms, and separate values are only generated for the continuous part, then a correlation will be introduced between all wind farms.

Table 2 *Example of available generation capacity model (expressed as % of the installed capacity) for a block of wind power units.*

Initial forecast	Updated forecast	Real outcome
75	75	75
25	75	75
75	25	75
25	25	75
75	75	25
25	75	25
75	25	25
25	25	25

Frequency Control Reserve

Non-dispatchable units cannot be used for frequency control and the frequency control reserve property of all non-dispatchable units should therefore be set to zero.

3.1.5 Consumers

The consumers are modelled as equivalent consumers, which represents the total consumption a large number of consumers with similar properties—in this case consumers that are clients to the same balance responsible player and pay the same retail price.

The following subsections will describe the properties of consumers which are included in the model.

Retail Price

Each equivalent consumer is assumed to have take-and-pay contract with a fixed price. This means that the consumers may consume as much as they want per trading period and pay the same price per MWh of consumed electricity regardless of the market price for that trading period. Thus, the balance responsible player is subject to a price risk, since there is a possibility that the balance responsible player will have to buy energy at a market price which is higher than the retail price that the consumers are charged.

Demand

Since consumers with take-and-pay contracts do not have to follow a certain consumption plan, the balance responsible players will have to forecast their demand. Hence, the model will require that forecasts and real outcome of the consumption can be randomised. The demand is also a continuous random variable; therefore, the same forecast model as for non-dispatchable generating units could be used.

However, the forecast error can sometimes be approximated by a normal distribution. Assume that the real outcome of the consumption of a consumer has been generated. The forecasts at various time steps is generating by multiplying the real outcome with a relative forecast factor. The relative forecast factor is a vector of normally distributed random numbers, with one element for each forecast. The mean of the relative forecast factors is one for each element, and the standard deviations depend on the accuracy of the forecast; a high standard deviation corresponds to a less accurate forecast. The elements of the relative forecast vector are correlated, so that if the factor for one time step is larger than zero (i.e., overestimating the demand) then it is more likely that the other factors are larger than one too. Generating correlated random numbers for the relative forecast factor vector can be done using the method described in for example [5][4].

Load Reduction

In this model, no distinction will be made between different forms of contracts that promote flexible consumption. It is simply assumed that flexible consumers have an agreement with their balance responsible player which will make the consumer reduce their electricity consumption during peak price periods, i.e., if the price in the ahead market exceeds a certain threshold then the flexible consumers will reduce their consumption. The size of the consumption decrease is however not known to the balance responsible player, which therefore will have to make a forecast for the size of the load reduction. The probability distribution of the forecasted and actual load reduction can be obtained in a similar manner as the model for the demand.

3.2 Monte Carlo Simulation

A general way to describe many simulation problems is to consider a mathematical model, g, with a set of random inputs, Y, and a set of random outputs, X, such that $X = g(Y)$. The system may of course have more than one input and more than one output, i.e., Y and X should be considered as vectors of random variables. The probability distribution of the inputs, F_Y, must be *known*, whereas the probability distribution of the outputs, F_X, is *unknown*. The objective of the simulation is to estimate the statistical properties of F_X. In a Monte Carlo simulation, the probability distribution F_X is investigated by randomising a series of outcomes of Y. A combination of random values for each element in Y defines a specific state of the system, and will therefore be referred to as a *scenario*. The response of the system to a specific scenario is calculated using the mathematical model, i.e., $x = g(y)$ is the result of the scenario y.

In simple sampling, the expectation value of the outputs, $E[X]$, is estimated as the mean result from n scenarios, $y_1,\ldots,y_n$, i.e., by calculating

$$m_X = \frac{1}{n}\sum_{i=1}^{n} g(y_i). \tag{2}$$

The necessary steps to perform a simulation using simple sampling are outlined in Figure 6. Further details about the procedure of a Monte Carlo simulation can for example be found in [1]. Random values, U, which are uniformly distributed between 0 and 1, are produced by a so-called pseudorandom number generator. These uniformly distributed random numbers can then be transformed into a suitable distribution using the inverse transform method (or some other transformation method). To create a *scenario* for the simulation, one random value has to be assigned to each of the inputs to the model. The model is then applied to each generated scenario and the results are used to estimate the expectation value of the outputs according to (2).

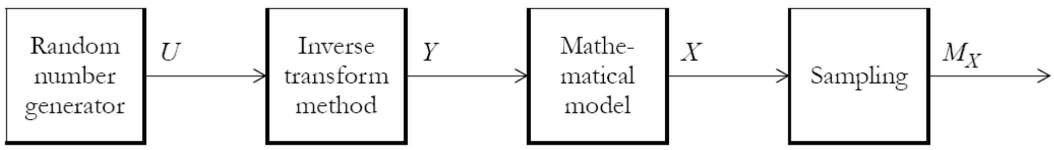

Figure 6 *Simulation procedure for simple sampling.*

When comparing different alternative models, it can be very efficient to use *correlated* sampling. The idea is that each generated scenario is tested in each of the models to be studied. The procedure for comparing two systems is outlined in Figure 7, but a similar strategy can be applied to compare the first model to any number of related models. In the case of two alternative models $x_1 = g_1(y)$ and $x_2 = g_2(y)$, the expected difference between the models, i.e., $E[X_1 - X_2]$, can be estimated by

$$m_{(X_1-X_2)} = \frac{1}{n}\sum_{i=1}^{n}(g_1(y_i) - g_2(y_i)). \tag{3}$$

It can be shown that as long as the models g_1 and g_2 are only slightly different, the estimated difference $m_{(X_1-X_2)}$, according to (3) can be expected to be more accurate than estimating m_{X_1} and m_{X_2} using simple sampling on two independent sets of n scenarios $y_{1,1},\ldots,y_{1,n}$ and $y_{2,1},\ldots,y_{2,n}$ respectively.

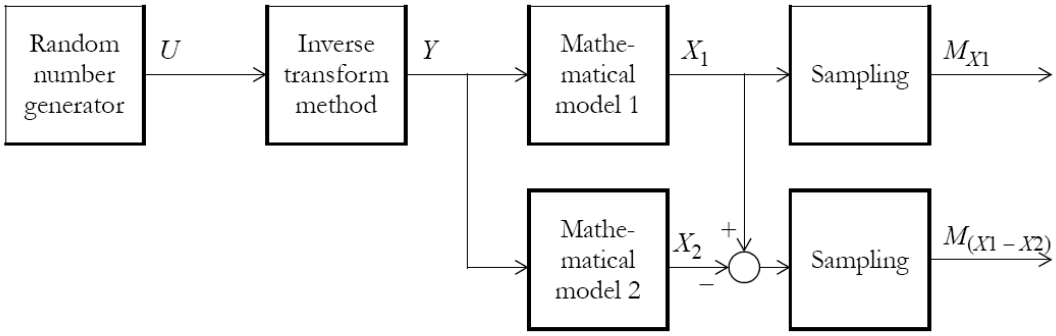

Figure 7 *Simulation procedure for correlated sampling of two systems.*

3.3 Scenario Model

The scenario model refers to the calculations that are performed to calculate the output values for a specific scenario, i.e., the scenario model corresponds to the function g in equations (2) and (3). When simulating the trading procedure of an electricity market, g will not be a straightforward mathematical expression, but the result of a sequence of calculations. An overview of this sequence will be given in this section.

3.3.1 Inputs and Outputs

This section provides a complete overview of the notation that is used in the description of the scenario model.

Inputs

The inputs to the scenario model can be divided into two groups: random inputs and system parameters. The random inputs have to be assigned a value from the appropriate probability distribution according to the principles described in section 3.2.

The following random inputs are used in the scenario model:

- $\bar{D}_{c,a}$ maximal load of consumer c according to the forecast from ahead market phase a
- $\bar{D}_{c,r}$ actual maximal load of consumer c in real-time phase r
- $\bar{D}^{\Downarrow}_{c,a}$ maximal load reduction of consumer c according to the forecast from ahead market phase a
- $\bar{D}^{\Downarrow}_{c,r}$ actual load reduction of consumer c in real-time phase r
- $\bar{G}_{g,a}$ available generation capacity of unit g according to the forecast from ahead market phase a
- $\bar{G}_{g,r}$ actual available generation capacity of unit g in real-time phase r

The system parameters depend describe the non-random properties of the players of the system, as well as the properties of the trading arrangement that is used. The following system parameters are used in this model:

β_{Gg} variable generation cost of unit g

C_a index set of consumers that participate in ahead market phase a

$\mathcal{G}_a$ index set of generating units that participate in the ahead market phase a

$\mathcal{G}_D$ index set of dispatchable generating units

$\mathcal{G}_N$ index set of non-dispatchable generating units

G_g^{FR} frequency control reserve of unit g

$\mathcal{G}_R$ index set of generating units that participate in the real-time balancing market

γ_{Gg}^{+} up-regulation cost of unit g

γ_{Gg}^{-} down-regulation cost of unit g

ι_D imbalance fee for consumption imbalance

ι_G imbalance fee for generation imbalance

ι_{tot} imbalance fee for total imbalance

$\overline{\lambda}_c$ threshold price of consumer c for load reductions

ρ_c retail price paid by consumer c

T_r duration of real-time phase r

Outputs

$BRPS_{b,a}$ surplus of balance responsible player b from ahead market phase a

$BRPS_b^r$ surplus of balance responsible player b from real-time trading

$BRPS_{b,r}$ surplus of balance responsible player b from actual consumption and generation in real-time phase r

$BRPS_b^P$ surplus of balance responsible player b from post trading

$BRPS_b$ final surplus of balance responsible player b

$D_{c,a}$ planned consumption of consumer c after ahead market phase a

$\Delta D_{c,a}$ purchase of consumer c in ahead market phase a

$D_{c,r}$ actual load of consumer c in real-time phase r

ΔD_b consumption imbalance of balance responsible player b

$G_{g,a}$ planned generation of unit g after ahead market phase a

$\Delta G_{g,a}$ sales of unit g in ahead market phase a

G_g^A planned generation of unit g after the end of the ahead trading

$G_{g,r}$ actual generation of unit g in real-time phase r

$G_{g,r}^{FR}$ available frequency control reserve of unit g in real-time phase r

G_{tot}^{FR} total available frequency control reserve

$\overline{\Delta G_{g,r}^{+}}$ available up-regulation bid of unit g in real-time phase r

$\Delta G_{g,r}^{+}$ activated up-regulation bid of unit g in real-time phase r

$\overline{\Delta G_{g,r}^{-}}$ available down-regulation bid of unit g in real-time phase r

$\Delta G^{-}_{g,r}$ activated down-regulation bid of unit g in real-time phase r
ΔG_b generation imbalance of balance responsible player b
I_a imbalance to be covered in ahead market phase a
I_r imbalance to be covered in real-time phase r
λ_a electricity price in ahead market phase a
λ^A reference electricity price from the ahead market
λ_r electricity price in real-time phase r
$\lambda_{\uparrow}$ up-regulation price
$\lambda_{\downarrow}$ down-regulation price
λ_b total imbalance power price of balance responsible player b
λ_{Gb} generation imbalance power price of balance responsible player b
λ_{Db} consumption imbalance power price of balance responsible player b

3.3.2 Ahead Market Trading

The trading in the ahead market can be divided in a number of phases, and a player does not have to participate in each phase of ahead market. For example, if a model includes a spot market phase and an adjustment market phase, a player could be submitting bids only to the spot market. It is assumed that there will be one unique electricity price for each phase of the ahead market trading. This corresponds to an electricity market where all players have access to the same forecasts (symmetric information) and where there is perfect competition.

The first step in each ahead market phase is to determine the total demand. Producers who are not active in phase a will stay on the same planned generation as after the previous phase, i.e.,

$$G_{g,a} = G_{g,a-1} \ \forall \ g \notin \mathcal{G}_a, \tag{4}$$

and so will consumers who are not active; thus,

$$D_{c,a} = D_{c,a-1} \ \forall \ c \notin \mathcal{C}_a. \tag{5}$$

Active consumers on the other hand will change their purchase so that it matches their latest forecast:

$$D_{c,a} = \bar{D}_{c,a} \ \forall \ c \in \mathcal{C}_a. \tag{6}$$

This means that the demand to be covered by the active producers can be calculated by

$$I_a = \sum_{c \in C} D_{c,a} - \sum_{g \notin \mathcal{G}_a} G_{g,a}. \tag{7}$$

The bids of the active producers will be accepted according to increasing bid price, which means that the total generation cost will be minimised. Hence, the planned generation of the active producers after phase a can be determined by solving the following optimisation problem:

$$\text{minimise} \sum_{g \in \mathcal{G}_a} \beta_{Gg} G_{g,a} \tag{8}$$

$$\text{subject to} \sum_{g \in \mathcal{G}_a} G_{g,a} = I_a$$

$$0 \le G_{g,a} \le \overline{G}_{g,a}, g \in \mathcal{G}_a.$$

The ahead market price for this phase, λ_a, is given by highest price of the accepted bids, which corresponds to the dual variable of the equality constraint in the optimisation problem (8).

If the resulting ahead market price is higher than the threshold for load reduction of some flexible consumers, the demand of that consumer is reduced, i.e.,

$$D_{c,a} = \overline{D}_{c,a} - D^{\Downarrow}_{c,a} \quad \forall \ \{c : \lambda_a > \overline{\lambda}_c\}. \tag{9}$$

The sales of unit g in ahead market phase a is calculated as the difference between planned generation before and after the phase:

$$\Delta G_{g,a} = G_{g,a} - G_{g,a-1}, \tag{10}$$

where the planned generation before the first phase, $G_{g,0}$, is zero by definition. Similarly, the purchase of load c is given by

$$\Delta D_{c,a} = D_{c,a} - D_{c,a-1}, \tag{11}$$

It should be noted that $\Delta G_{g,a}$ as well as $\Delta D_{c,a}$ can be negative. For example, if a planned generation of a power plant is 1 000 MWh ($G_{g,1} = 1000$) after the first ahead market phase and 900 MWh after the second ($G_{g,2} = 900$) then the producer sold 1 000 MWh in the first phase and purchased 100 MWh in the second (as the sales are negative).

The surplus of a balance responsible player's trading in phase a is then obtained by multiplying the sales and purchase of all the clients of the balance responsible player by the market price for the phase, i.e.,

$$BRPS_{b,a} = \lambda_a \Big(\sum_{g \in \mathcal{G}_b} \Delta G_{g,a} - \sum_{c \in \mathcal{C}_b} \Delta D_{c,a} \Big). \tag{12}$$

3.3.3 Real-Time Trading

The real-time trading can also divided in a number of phases in order to simulate that generation and load may vary within a trading period. The first step in each real-time phase is to calculate the real-time balance of the system. All dispatchable units are assumed to be generating according to the plan after the last ahead market phase, unless the unit is subject to an outage, i.e., the real-time generation is initially assumed to be

$$G_{g,r} = \max(0, \min(G_g^A, \overline{G}_{g,r} - G_g^{FR})) \;\; \forall \;\; g \in \mathcal{G}_D. \tag{13}$$

Non-dispatchable units are assumed to generate their available generation capacity, i.e.,

$$G_{g,r} = \overline{G}_{g,r} \;\; \forall \;\; g \in \mathcal{G}_N. \tag{14}$$

The load of the consumers is assumed to be equal to the maximal demand minus any activated load reduction, i.e.,

$$D_{c,r} = \overline{D}_{c,r} - D_{c,r}^{\Downarrow} \;\; \forall \;\; c \in \mathcal{C}, \tag{15}$$

where $D_{c,r}^{\Downarrow}$ is equal to zero if the consumer load reduction was not activated during the ahead trading and equal to the maximal load reduction, $\overline{D}_{c,r}^{\Downarrow}$, if the price during the ahead trading exceeded the threshold price of the consumer.

The real-time imbalance is now given by

$$I_r = \sum_{g \in \mathcal{G}} G_{g,r} - \sum_{c \in \mathcal{C}} D_{c,r}.$$

Up-regulation

If the real-time imbalance, I_r, is less than zero then there is a shortage of power in the system, and the system operator might have to activate up-regulation bids if the shortage is larger than the reserves available for frequency control. The total frequency control reserve is given by

$$G_{tot}^{FR} = \sum_{g \in \mathcal{G}} G_{g,r}^{FR}, \tag{16}$$

where the frequency reserve available in unit g is given by

$$G_{g,r}^{FR} = \begin{cases} 0 \text{ if unit } g \text{ is unavailable,} \\ G_g^{FR} \text{ if unit } g \text{ is available.} \end{cases} \tag{17}$$

If imbalance is less than the total frequency control reserve, i.e., if $|I_r| \le G_{tot}^{FR}$, then the imbalance is assumed to be covered by the generating units of the frequency control reserve. Each of these units will update its generation according to its share of the total frequency control reserve; thus, the up-regulation for this phase is given by

$$\Delta G_{g,r}^{+} = |I_r| \cdot \frac{G_{g,r}^{FR}}{G_{tot}^{FR}}. \tag{18}$$

Since no up-regulation bids have been activated, the real-time price for this phase remains equal to the reference price from the ahead market, i.e., $\lambda_r = \lambda^A$.

If the imbalance on the other hand is larger than the total frequency control reserve, the system operator will have to activate one or more up-regulation bids. The producers who are active in the real-time balancing market are expected to submit up-regulation bids where the upper limit of the bid is given by the unused capacity of the unit minus the capacity that is dedicated as frequency reserve.

$$\overline{\Delta G^{+}_{g,r}} = \max(0, \overline{G}_{g,r} - G^{A}_{g} - G^{FR}_{g}) \;\; \forall \;\; g \in \mathcal{G}_{R}. \quad (19)$$

The up-regulation bids will be activated according to increasing bid price until the imbalance has been mitigated. This means that the system operator is solving the following optimisation problem:

$$\text{minimise} \sum_{g \in \mathcal{G}_{r}} (\beta_{Gg} + \gamma^{+}_{Gg}) \Delta G^{+}_{g,r} \quad (20)$$

$$\text{subject to} \quad \sum_{g \in \mathcal{G}_{r}} \Delta G^{+}_{g,r} = -I_{r}$$

$$0 \leq \Delta G^{+}_{g,r} \leq \overline{\Delta G^{+}_{g,r}}, g \in \mathcal{G}_{r}.$$

The real-time price for this phase, λ_{r}, is given by highest price of the activated bids, which corresponds to the dual variable of the equality constraint in the optimisation problem (20).

Once the up-regulation per unit has been calculated, the final real-time generation for the dispatchable units can be calculated as

$$G_{g,r} = G^{A}_{g} + \Delta G^{+}_{g,r} \;\; \forall \;\; g \in \mathcal{G}_{D}. \quad (21)$$

Down-regulation

If the real-time imbalance, I_{r}, is larger than zero then there is an excess of power in the system, and the system operator might have to activate down-regulation bids if the excess is larger than the reserves available for frequency control. The total frequency control reserve is given by

$$G^{FR}_{tot} = \sum_{g \in \mathcal{G}} G^{FR}_{g,r}, \quad (22)$$

where the frequency reserve available in unit g is given by

$$G^{FR}_{g,r} = \min(G^{A}_{g}, G^{FR}_{g}). \quad (23)$$

If imbalance is less than the total frequency control reserve, i.e., if $I_{r} \leq G^{FR}_{tot}$, then the imbalance is assumed to be covered by the generating units of the frequency control reserve. Each of these units will update its generation according to its share of the total frequency control reserve; thus, the up-regulation for this phase is given by

$$\Delta G^{-}_{g,r} = I_r \cdot \frac{G^{FR}_{g,r}}{G^{FR}_{tot}}. \tag{24}$$

Since no down-regulation bids have been activated, the real-time price for this phase remains equal to the reference price from the ahead market, i.e., $\lambda_r = \lambda^A$.

If the imbalance on the other hand is larger than the total frequency control reserve, the system operator will have to activate one or more down-regulation bids. The producers who are active in the real-time balancing market are expected to submit down-regulation bids where the upper limit of the bid is given by the planned generation minus the capacity that is dedicated as frequency reserve.

$$\overline{\Delta G^{-}_{g,r}} = \max(0, G^A_g - G^{FR}_g) \;\; \forall \;\; g \in \mathcal{G}_R. \tag{25}$$

The down-regulation bids will be activated according to decreasing bid price until the imbalance has been mitigated. This means that the system operator is solving the following optimisation problem:

$$\text{maximise} \sum_{g \in \mathcal{G}_r} (\beta_{Gg} - \gamma^{-}_{Gg}) \Delta G^{-}_{g,r} \tag{26}$$

$$\text{subject to} \sum_{g \in \mathcal{G}_r} \Delta G^{-}_{g,r} = I_r$$

$$0 \le \Delta G^{-}_{g,r} \le \overline{\Delta G^{-}_{g,r}}, g \in \mathcal{G}_r.$$

The real-time price for this phase, λ_r, is given by lowest price of the activated bids, which corresponds to the dual variable of the equality constraint in the optimisation problem (26).

Once the down-regulation per unit has been calculated, the final real-time generation for the dispatchable units can be calculated as

$$G_{g,r} = G^A_g - \Delta G^{-}_{g,r} \;\; \forall \;\; g \in \mathcal{G}_D. \tag{27}$$

Results from Real-Time Trading

The up-regulation price is defined as the highest real-time price of the trading period, i.e.,

$$\lambda_{\uparrow} = \max \lambda_r. \tag{28}$$

Similarly, the down-regulation price is defined as the lowest real-time price of the trading period:

$$\lambda_{\downarrow} = \min \lambda_r. \tag{29}$$

All up-regulation means that the producer is selling energy to the system operator, regardless of whether the up-regulation is due to activated up-regulation bids in the real-time balancing market or automatic up-regulation performed by the frequency control. All energy that is sold is paid the up-regulation price. All down-regulation means that the producer is buying energy from the system operator and the price for these transactions are given by the down-regulation price. The surplus of the trading in the real-time balancing market for a certain balance responsible player is consequently given by

$$BRPS_b^R = \lambda_\uparrow \sum_{g \in \mathcal{G}_b} \sum_{r \in \mathcal{R}} T_r \Delta G_{g,r}^+ - \lambda_\downarrow \sum_{g \in \mathcal{G}_b} \sum_{r \in \mathcal{R}} T_r \Delta G_{g,r}^-, \tag{30}$$

where T_r is the length of real-time period r.

The real-time trading also determines the actual operation costs of the generators and the actual consumption of the consumers. The surplus of sales and generation costs is calculated by

$$BRPS_{b,r} = T_r (\sum_{c \in \mathcal{C}_b} \rho_c D_{c,r} - \sum_{g \in \mathcal{G}_b} \beta_{Gg} G_{g,r}), \tag{31}$$

where $D_{c,r}$ is calculated according to (15) and $G_{g,r}$ is calculated according to (21) or (27) depending on the direction of the real-time imbalance in phase r.

3.3.4 Post Market Trading

The imbalance prices depends on the results of the ahead market trading and the real-time trading, as well as which imbalance pricing scheme that is used. The reference price is given by the price at one of market places of the ahead trading. In the model, this means that the price of one of the ahead market phases is selected as reference price. The up- and down-regulation prices correspond to their counterparts from the real-time trading.

The post market model can be adapted to any of the post market pricing schemes discussed in section 2.3. However, the case studies in chapter 4 will focus on a pricing system where production imbalances are separated from consumption imbalances. Hence, two imbalances will be calculated for each balance responsible player:

$$\Delta G_b = \sum_{g \in \mathcal{G}_b} \sum_{r \in \mathcal{R}} T_r G_{g,r} - \sum_{g \in \mathcal{G}_b} G_g^A - \sum_{g \in \mathcal{G}_b} \sum_{r \in \mathcal{R}} T_r \left(\Delta G_{g,r}^+ - \Delta G_{g,r}^- \right), \tag{32}$$

$$\Delta D_b = \sum_{c \in \mathcal{C}_b} D_c^A - \sum_{c \in \mathcal{C}_b} \sum_{r \in \mathcal{R}} T_r D_{c,r}. \tag{33}$$

The production imbalance is defined as the actual generation—the first term in (32)—minus the sales in the ahead market—the second term in (32)—and minus the sales or purchase in the real-time market. The consumption imbalance is a similar expression, but it is assumed that consumers are not participating in the real-time trading; thus, there is no third term in (33).

The imbalance settlement cost of a balance responsible player is given by

$$BRPS_b^P = \lambda_b(\Delta G_b - \Delta D_b) - \iota_{tot}\left|\Delta G_b - \Delta D_b\right| + \lambda_{Gb}\Delta G_b - \iota_G\left|\Delta G_b\right| + \lambda_{Db}\Delta D_b - \iota_D\left|\Delta D_b\right|, \quad (34)$$

where the imbalance prices (λ_b, λ_{Gb} and λ_{Db}) are set depending on which imbalance pricing scheme that is used (cf. section 2.3). Imbalance prices and fees for imbalances that are not applied in a given trading arrangement should be set to zero. For example, if only the generation and consumption imbalances are considered then λ_b and ι_{tot} are set to zero.

Once the results of the post trading has been determined, it is possible to calculate the final surplus of a balance responsible player as the sum of the results the ahead trading, real-time trading and post trading:

$$BRPS_b = \sum_{a \in \mathcal{A}} BRPS_{b,a} + BRPS_b^R + \sum_{r \in \mathcal{R}} BRPS_{b,r} + BRPS_b^P. \quad (35)$$

4 Case Study

The objective of the case study presented in this chapter is to examine the importance of different changes in the trading arrangements of an electricity market with large amounts of wind power. The study includes test systems with varying characteristics in terms of amount of wind power, other generation resources as well as demand level. Each test system has then been simulated for a set of different trading arrangements.

The test systems have been designed to have similar properties as can be found in the Nordic electricity market. However, it must be stressed that the test systems are indeed fictitious, and the results obtained here are not intended as accurate predictions of the values of different trading arrangements on the Nordic Market; the objective of the case study is to identify trends and to investigate which factors that influence the consequences of a certain trading arrangement.

4.1 Test System Design

The test systems used in the case study have the same basic design, as described in section 4.1.1 below. In addition to these general properties, each test system also has its own specific properties. The specific properties are varied in two areas: the general price levels and the trading arrangements. The general price level depends on the generation resources of the system and the demand. Further details about these properties are given in section 4.1.2. Each configuration of resources and demand has then been simulated using eight different combinations of trading arrangements. Details about the trading arrangements are provided in section 4.1.2.

4.1.1 General Properties

This section provides information about the assumptions and model data that are common to all test systems. Some further details can be found in appendix B.

Organisation of the Electricity Market

The ahead market in the test systems consists only of a spot market, i.e., bilateral trading and the adjustment market is neglected. It is assumed that the highest possible bid price is 200¤/MWh.

The model of the real-time balancing market consists of one real-time phase. This simplifies the randomisation of available generation capacity and load, but also means that there will not be any trading periods with both up- and down-regulation in the test systems (cf. section 3.1.1). However, such trading periods are quite rare in the Nordic electricity market; up- and down-regulation in the same hour occurs in less than 1% of the hours [12]. Only some producers are assumed to participate in the real-time balancing market. Power plants participating in the real-time balancing market will submit up-regulation bids if their planned generation is less than the available capacity and down-regulation bid if their planned generation is larger than zero. The submitted bids are equal to the variable operation cost of the power plant plus an up-regulation fee (in case of an up-regulation bid) or variable operation cost minus a down-regulation fee (in case of a down-regulation bid).

In the post market, there will be a production imbalance and a consumption imbalance for each balance responsible player. A two-price system is applied to the production imbalance. For consumption, a one-price system is used, but on the other hand there is a imbalance fee of 0.1 ¤/MWh for all consumption imbalances. In case of power deficit, the artificial price for negative imbalances is set to 2 000 ¤/MWh.[3]

Balance Responsible Players

In each test system, a number of balance responsible players have been defined. The objective of introducing these players is to investigate how the impact of the trading arrangements depend on the conditions of the players, i.e., in which markets are they active, how large forecast errors are they subject to (in comparison to their total trading), etc. The balance responsible players are divided in the five groups with the following typical properties:

- **Independent wind power producer.** This refers to a player who is only operating wind power plants. Each independent wind power producer has only a small part of the total wind power capacity of the system. The generated electricity is sold in the spot market and the wind power producers do not participate in the real-time trading.

- **Independent retailer.** An independent retailer is buying electricity from the spot market and selling it to the final customers for a fixed price.

- **Small utility.** A small utility operates both wind power and conventional power plants. Each small utility has only a small part of the total wind power capacity of the system. The installed capacity of the wind power is in the same size of order as the installed capacity of the conventional units (cf. Table 14 and Table 15 in appendix B). Small utilities also sell electricity to final customers for a fixed price. Most of the time, these utilities will be net buyers from the spot market. Small utilities do not participate in the real-time trading.

- **Large utility.** As for small utilities, these players have both wind power and conventional power, and they sell to final customers. The difference is that they are net sellers of electricity in the spot market, and that they may be responsible for a significant part of the installed wind power capacity, but the wind power capacity of each large utility is still small compared to the total capacity of the utility (cf. Table 14 and Table 15 in appendix B). Large utilities participate in the real-time trading, although only with a part of their total capacity.

- **Peak power producers.** It is interesting to see how the trading arrangement affect the profitability of peak power plants (and thus the interest for investing in peak capacity). As the model calculates the surplus of balance responsible players–not individual power plants–it is then necessary to define separate balance responsible players for each peak power unit. The

[3] The rules for the post market has been designed to correspond to the rules applied by Svenska kraftnät from 1 January 2009 (cf. [2]).

peak power units sell electricity to the spot market and participate in the real-time trading.

4.1.2 General Price Levels

The impact of the different trading properties may vary depending on which system is studied; therefore, the case study includes five different system configurations with different price levels in the spot market and real-time balancing market respectively. The spot prices mostly depend on the installed capacity and the variable operation costs of the conventional units in the system, whereas the real-time balancing prices mostly depend on the number of power plants participating in the real-time trading, the variable operation costs of those plants and the up- and down-regulation fees. The general price levels are also influenced by the amount of wind power and the load of the system. An overview of the most important factors is given in Table 3.

Two possible set-ups (referred to as "SE" and "DK" respectively) of conventional power plants have been created. The starting point then these set-ups were designed was that SE conventional units should result in electricity prices resembling those recorded in Sweden between 2003–2005 for a system with small amounts of wind power, low load and default trading arrangements.[4] Similarly, the DK conventional units should result in electricity prices resembling those recorded in Western Denmark 2006–2008 for a system with medium amounts of wind power, low load and default trading arrangements.

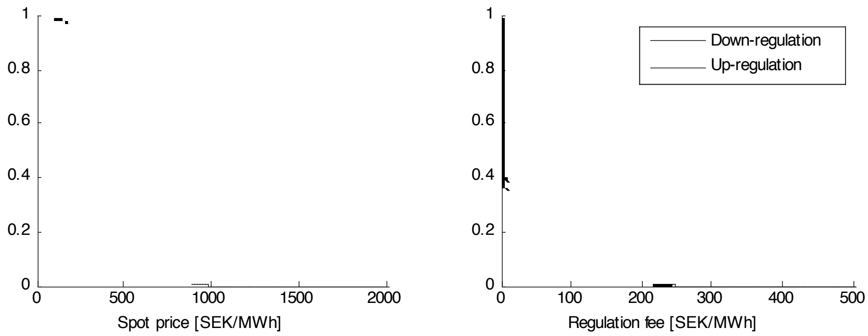

Figure 8 *Swedish electricity prices from 2003-2005. (Source: Nord Pool)*

[4] The default trading arrangements refers to the system that corresponds to the present trading arrangements in the Nordic electricity market, i.e., day-ahead spot market, wind power is accounted as production in the post market and low consumption flexibility (cf. section 4.1.3).

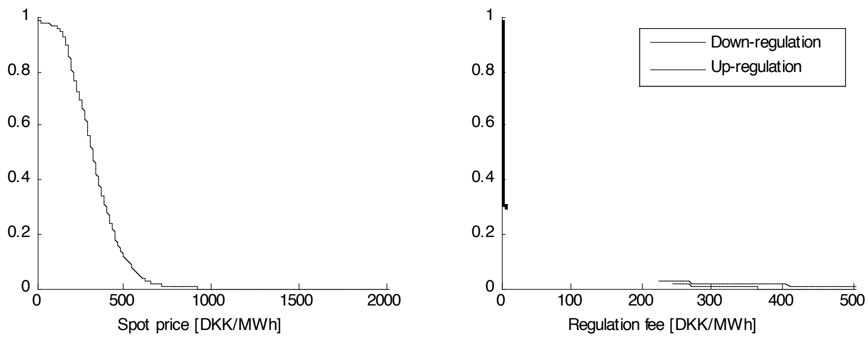

Figure 9 *Danish electricity prices from 2006-2008. (Source: Nord Pool)*

Table 3 *Overview of the main test systems.*

Set-up of conventional units	Conventional units		Amount of wind power	Mean demand
	Not active in real-time trading	Active in real-time trading		
SE	13 200 MW	3 900 MW	Small (350 MW)	Low (10 000 MW)
SE	13 200 MW	3 900 MW	Medium (2 200 MW)	Low (10 000 MW)
SE	13 200 MW	3 900 MW	Large (4 400 MW)	High (11 000 MW)
DK	8 350 MW	7 000	Medium (3 000 MW)	Low (10 000 MW)
DK	8 350 MW	7 000	Large (6 000 MW)	High (10 000 MW)

4.1.3 Trading Arrangements

The main purpose of the case study is to study the impact of different choices for the trading arrangements in the test systems. There are three properties of the trading arrangements that are varied for the test systems, namely the planning horizon, the imbalances pricing and the consumption flexibility.

Planning Horizon

The delay time between the closure of the spot market and the delivery hour determines the size of the forecast errors. Two alternative planning horizons are used in the test systems:[5]

- **Day-ahead market.** The day-ahead market alternative corresponds to an arrangement where bids have to be submitted on the day before delivery.
- **Intra-day market.** In this alternative it is assumed that there are several gate closures of the spot market for each day; hence, there will only be a short delay from the submission of bids to the spot market until the delivery hour.

The wind power forecast model is based on one year of forecast data from some Scandinavian wind power plants. These data have been used to estimate a forecast model with 40 discrete levels in each phase (day-ahead market forecast, intra-day market forecast and real outcome) according to the

[5] It should be noted that although each test system is using either the day-ahead market forecast model or the intra-day market forecast model, the forecasts have to be randomised simultaneously when a scenario is created, as it would otherwise not be possible to apply correlated sampling (cf. section 3.2).

principles outlined in section 3.1.4. It is assumed that there is a strong correlation between the wind generation of different balance responsible players, i.e., the same discrete values—$\overline{W}_t^D$ in equation (1)—are used for all players in each scenario.

The day-ahead market forecasts are based on errors in forecasts that were made between 12 to 36 hours ahead, i.e., the planning horizon that is applicable to the current trading arrangements of the Nord Pool Elspot market. The intra-day forecasts are based on a one-hour persistence forecast, which means that the wind power generation one hour is assumed to be equal to the generation during the previous. The forecast errors in the intra-day model are most likely smaller than what would actually be possible to achieve in the Nordic electricity market unless there is also an improvement in the forecasting tools. Nevertheless, the intra-day forecast model has been considered in this study as they give an indication of the benefits of significantly reduced forecast errors.

Figure 10 shows the probability distribution of the forecast error in MW for a producer with 100 MW installed capacity of wind power. It can be observed that the forecast error is almost always within ±20 MW for the day-ahead forecast, compared to ±10 MW for the intra-day forecast. Moreover, it can be observed that the two probability distributions have more or less the same shape. Hence, 100 MW of wind power in a day-ahead market causes the approximately the same forecast errors as 200 MW of wind power in an intra-day market.

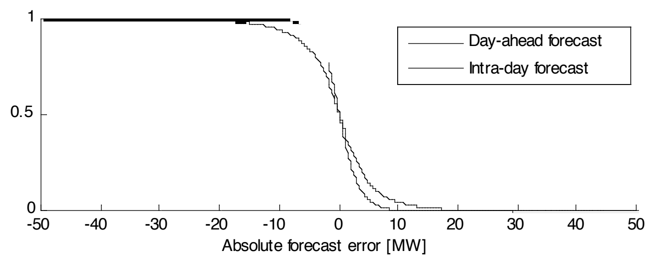

Figure 10 *Forecast error for a wind power producer with 100 MW installed capacity.*

The model of load forecasts is not based on actual data, but it has been assumed that the load itself is normally distributed. The forecasts are generated by multiplying the actual load with a random factor for the day-ahead forecast and the intraday forecast respectively. The probability distribution of these random factors has been chosen so that the resulting consumption imbalances correspond to the average consumption imbalances observed on the Swedish electricity market [4]. As can be seen in the statistics, there is in reality a large variation between mean consumption imbalances of different balance responsible players. However, as the statistics do not indicate what kind of players it is that have the smaller and larger forecast errors respectively, the same load forecast model has been used for all balance responsible players in this case study.

Figure 11 shows the probability distribution of the forecast error in MW for a retailer with a mean load of 100 MW. It can be observed that the load forecast errors are small compared to the wind power forecast errors, and it is assumed that the size of the forecast errors does not depend that much on the planning horizon.

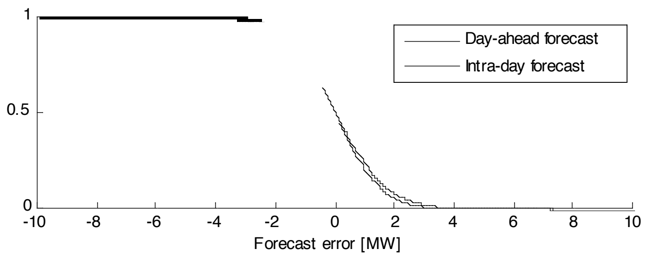

Figure 11 *Forecast error for a retailer with a mean load of 100 MW.*

In scientific literature, forecast errors are often expressed as RMSE values (see appendix A for further details). The NRMSE value of the wind power forecast error is 6.7% of the installed capacity for the day-ahead model and 3.5% for the intra-day model. The CV-RMSE value of the load forecast error is 1.5% of the mean load for the day-ahead model and 1.3% for the intra-day model.

In addition to the wind power and load forecasts, the model also includes forecasts for conventional units and load reductions. The conventional units are divided in hydro units and thermal units. Hydro power is in general very reliable, and in this case study it is assumed that all hydro power units have 100% availability; therefore, there will not be any forecast errors in the hydro power units regardless of the planning horizon. The thermal units are assumed to have a reliability of 95%. It is assumed that the players use a persistence forecast for the available generation capacity of the thermal units, which means that if a unit is available when the spot market bid has to be submitted then the forecast is that it will also be available during the delivery hour. Similarly, if the unit is unavailable at the time of the spot market bid then it is assumed not to be repaired before the delivery hour. In the intra-day market, the probability that a unit will fail or be repaired in the time between the gate closure and the delivery hour is considered negligible, i.e., there will not be any forecast errors in this case. However, in the day-ahead market, it is assumed that there is a possibility that the persistence forecast is incorrect. Consequently, there are four possible outcomes of forecasted and real available generation capacity for each thermal unit, as listed in Table 4 below.

Table 4 *Available generation capacity model for thermal power plants in the test systems.*

Day-ahead market forecast	Intra-day market forecast	Real outcome	Probability [%]
Available	Available	Available	94.8
Unavailable	Available	Available	0.2
Available	Unavailable	Unavailable	0.2
Unavailable	Unavailable	Unavailable	4.8

The load reduction forecasts are modelled in the same way as the load forecasts, i.e., by introducing random factors for the day-ahead forecast and the intraday forecast respectively. The load reduction forecast error is almost the same for both planning horizons.

Imbalance Pricing

It has already been mentioned that two imbalances are used in the test system; one for production and one for consumption, where a two-price imbalance pricing system is used for production and a one-price system is used for consumption. Since a one-price system is preferable for balance responsible players who cannot avoid forecast errors, it would be beneficial for wind power producers if a one-price system was applied to wind power generation. Therefore, two alternative imbalance pricing systems are used in the test systems:

- **Wind power as generation.** Wind power generation is accounted for in the production balance.
- **Wind power as negative load.** Wind power is considered as negative load and accounted for in the consumption balance.

Consumption Flexibility

It is assumed that all retailers sell electricity to consumers at a fixed price (32 ¤/MWh and 38 ¤/MWh in test systems SE and DK respectively). Hence, retailers will make a loss whenever the spot price exceeds the retailer price. It could therefore be interesting for retailers to introduce contracts that allow the retailer to control the load of the customers in case of extreme spot prices. Such contracts can be designed in different ways and may use different technologies to activate the load reduction.

Here, a simplified model for such contracts is used. The model assumes that if the spot price exceeds a certain level (100 ¤/MWh in the test systems) then the retailer can activate a certain load reduction of their customers. The size of this load reduction is not known by the retailer, but has to be forecasted. The actual load reduction is chosen to be uniformly distributed between 5% and 15% of the actual demand for that trading period. This probability distribution is based on findings from previous studies within the Elforsk Market Design programme, which have indicated that consumers may reduce their consumption by as much as 50% for a specific hour [9], [10]. Hence, if it is assumed that 20% of the consumption have such contracts, the average load reduction will be around 10%.

The practical difference between a market with only price insensitive consumption and a market with flexible consumption as outlined above, is that in the former case, the retailers will have to submit bids at the highest possible price in the spot market. An example of this is given in Figure 12. Here, the forecasted consumption of a retailer is 1 000 MW; hence, the retailer will buy 1 000 MW from the spot market as long as the price is less than 200 ¤/MWh (which is the maximum spot price in the test systems, and significantly higher than the variable operation cost, 120 ¤/MWh, of the most expensive peak capacity). With flexible consumption, the retailer will not have to bid maximum price for the entire consumption; the bid price can be set to the load reduction activation price for the part of the consumption that is forecasted to be eliminated if load reductions are activated. In the example the forecasted load reduction is 100 MW, which means that if the price is between 0 and 100 /MWh then the retailer will buy 1 000 MW, whereas if the spot price is between 100 and 200 ¤/MWh the retailer only needs to buy 900 MW.

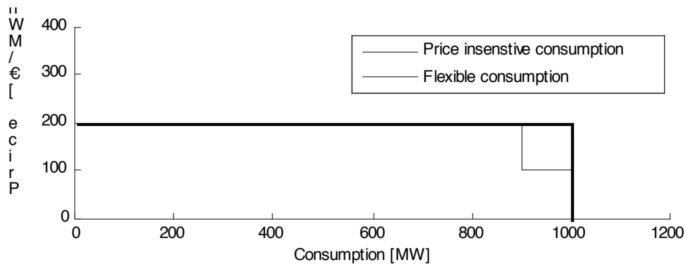

Figure 12 *Example of the difference between price insensitive consumers and flexible consumers.*

4.2 Results

This section includes presentation and discussion of the results from simulating the test systems. The simulations were performed using correlated sampling as described in section 3.2. Each simulation comprised 100 000 scenarios. The analysis is divided in two sections; one for the results on a system level (i.e., prices at different trading phases and the reliability of supply) and one that focus on the consequences for the different groups of balance responsible players.

4.2.1 Prices and Reliability

The trading arrangements will have an impact on prices in the spot market as well as in the real-time balancing market (and consequently in the post market too) and for the reliability of the system. This section provides an overview and discussion of the results of these system indices for the test systems.

Test System SE with Small Amounts of Wind Power and Low Load

An overview of prices and reliability of supply for this system is provided in Table 5. First of all, it can be noted that whether wind power is included in the production or the consumption imbalance only affects the post market trading. Consequently, this trading arrangement does not have any impact on the prices in neither the spot market nor the real-time balancing market. Moreover, it does not change the physical operation of the system and hence, the loss of load probability is not affected.

Table 5 *Overview of the results for test system SE with small amounts of wind power and low load.*

Intra-day trading	Wind power as negative load	Flexible consum-ers	Spot price [¤/MWh]	Down-regulation fee [¤/MWh]	Up-regulation fee [¤/MWh]	Risk of power deficit [%]	Probability of load reduction [%]
			29.30	1.98	1.35	0.18	—
✓			29.29	1.88	0.98	0.15	—
	✓		29.30	1.98	1.35	0.18	—
✓	✓		29.29	1.88	0.98	0.15	—
		✓	29.30	2.35	1.30	0.03	0.44
✓		✓	29.29	2.25	0.94	0.01	0.42
	✓	✓	29.30	2.35	1.30	0.03	0.44
✓	✓	✓	29.29	2.25	0.94	0.01	0.42

It can also be noted that neither of the other two trading arrangements have any impact on the spot price. (The small difference that is seen in the table is due to the uncertainty of the Monte Carlo simulation). This is not surprising, as the same physical resources and demand are assumed to be traded at the spot market regardless of the planning horizon–the planning horizon affects the size of *forecast errors* not the actual level of available generation and consumption. The presence of flexible consumers only changes the spot price for extreme scenarios, and the impact is too small to be observed in the mean spot price.

The real-time prices, i.e., down-regulation fee and up-regulation fee, depend on the amount of regulation activated by the system operator. The most important factor here is the planning horizon; switching to intra-day trading reduced the size of primarily the wind power forecast errors (see section 4.1.3) and reduced forecast errors mean lower regulation fees.

The impact of flexible consumption on real-time prices is more complex. The up-regulation fee is reduced, which indicates that the need for regulation has been decreased. However, the down-regulation fee is increasing. This seems contradictory, but there is a simple explanation. If the forecasts for the spot market result in shortage of supply, the spot price will be on the maximal price level of the consumption bid, i.e., 200 ¤/MWh. If it during real-time operation turns out that the forecasts were wrong, and that there actually is sufficient generation capacity to avoid power deficit, then the system operator will have to activate down-regulation bids. The down-regulation bids to be considered are in the price range 70–120 ¤/MWh, resulting in extreme down-regulation fees in the between 80 and 130 ¤/MWh. When more flexible consumption is introduced, the probability of these events increases.

An important reason to introduce flexibility in the residential consumers is to reduce the risk of power deficit. It can be seen that flexible consumption indeed reduces the risk significantly. The load reductions will of course not always solve the problem, and–due to forecast errors–may sometimes be activated although it is not really needed. To reduce the risk of power deficit from 0.18% to 0.03% (corresponding to 13 hours in a year) it will be necessary to activate the load reduction almost 40 hours per year. It can though be noted that field tests have indicated that customers accept load reductions up to 40 hours a year [10]. However, if flexible consumption contracts can be introduced for 40% of the consumption instead of 20% as assumed in section 4.1.3, then it would be possible to activate load reduction for only half of the customers at each single occasion. By this means, it would be possible to activate load reductions up to 80 hours a year.

According to the model, the risk of power deficit is also slightly decreased by switching from day-ahead to intra-day trading. The reason for this is that not all units participate in the real-time balancing market. If the forecast at the time of the spot market indicate that such a power plant is not needed, then it will not be possible for the system operator to activate that power plant during the real-time operation in case it turns out that the forecast was wrong. Since intra-day trading reduces the forecast errors, the risk of this kind of events will decrease.

Test System SE with Medium Amounts of Wind Power and Low Load

The results of this system are displayed in Table 6. Obviously, the introduction of more wind power while keeping the same conventional generation resources and having the same load, results in lower spot prices and decreased risk of power deficit compared to the previous system. At the same time, the extra wind power causes larger forecast errors; thus, the down- and up-regulation fees are increased.

The impact of the trading arrangements is similar to what we have seen for the previous system, but it can be noted that the relative size of the changes can differ. Switching from day-ahead to intra-day trading reduced the down-regulation fees by about 5% for small amounts of wind power; here the down-regulation fees decrease around 15%. For the up-regulation fees, the change is about 30% for both low and medium amounts of wind power. The decreased risk of power deficit thanks to the shorter planning horizon is also more or less the same, whereas the impact of flexible consumption is lesser in the system with medium amounts of wind power.

Table 6 *Overview of the results for test system SE with medium amounts of wind power and low load.*

Intra-day trading	Wind power as negative load	Flexible consum-ers	Spot price [¤/MWh]	Down-regulation fee [¤/MWh]	Up-regulation fee [¤/MWh]	Risk of power deficit [%]	Probability of load reduction [%]
			27.66	2.51	1.58	0.13	—
✓			27.65	2.06	1.07	0.10	—
	✓		27.66	2.51	1.58	0.13	—
✓	✓		27.65	2.06	1.07	0.10	—
		✓	27.66	2.76	1.54	0.02	0.29
✓		✓	27.65	2.30	1.05	0.01	0.28
	✓	✓	27.66	2.76	1.54	0.02	0.29
✓	✓	✓	27.65	2.30	1.05	0.01	0.28

Test System SE with Large Amounts of Wind Power and High Load

The results of the SE system with large amounts of wind power are presented in Table 7. Even though much more wind power is available than for the previous two systems, there is now also an increased load, and apparently the extra wind power is not sufficient compensation; hence, the mean spot price is higher and so is the risk of power deficit. The extra wind power is also causing much larger regulation fees than for the previous systems.

The impact of the trading arrangements is similar to what we have already seen. However, the importance of the trading arrangements is more visible in this system. The down-regulation fees decreases by more than 20% when the planning horizon is shortened, and the up-regulation fees decrease by more than 35%! The impact on the risk of power deficit is also more significant, and flexible consumers will have to accept a lot of activated load reductions (or the load reductions have to be distributed over a large group of consumers as discussed above).

Table 7 *Overview of the results for test system SE with large amounts of wind power and high load.*

Intra-day trading	Wind power as negative load	Flexible consum-ers	Spot price [¤/MWh]	Down-regulation fee [¤/MWh]	Up-regulation fee [¤/MWh]	Risk of power deficit [%]	Probability of load reduction [%]
			30.09	3.68	2.59	0.59	—
✓			30.05	2.73	1.67	0.47	—
	✓		30.09	3.68	2.59	0.59	—
✓	✓		30.05	2.73	1.67	0.47	—
		✓	30.09	4.51	2.46	0.17	0.99
✓		✓	30.05	3.59	1.56	0.07	0.99
	✓	✓	30.09	4.51	2.46	0.17	0.99
✓	✓	✓	30.05	3.59	1.56	0.07	0.99

Test System DK with Medium Amounts of Wind Power and Low Load

The results of this system are displayed in Table 8. The primary differences between the DK system and the SE system are that the spot prices are on a higher level as well as more volatile. Moreover, the regulation fees are higher. As before, the impact of the trading arrangement is similar to the other systems. Though the relative changes cannot be directly compared to the SE systems (since the conditions are slightly different) the results still indicate that the impact of the trading arrangement has a larger importance in systems where it is necessary to activate a lot of regulation bids in the real-time balancing market and where the risk of power deficit is high.

Table 8 *Overview of the results for test system DK with medium amounts of wind power and low load.*

Intra-day trading	Wind power as negative load	Flexible consum-ers	Spot price [¤/MWh]	Down-regulation fee [¤/MWh]	Up-regulation fee [¤/MWh]	Risk of power deficit [%]	Probability of load reduction [%]
			33.36	2.76	3.16	0.27	—
✓			33.29	2.01	2.05	0.23	—
	✓		33.36	2.76	3.16	0.27	—
✓	✓		33.29	2.01	2.05	0.23	—
		✓	33.36	3.20	3.10	0.08	0.48
✓		✓	33.29	2.46	2.00	0.04	0.47
	✓	✓	33.36	3.20	3.10	0.08	0.48
✓	✓	✓	33.29	2.46	2.00	0.04	0.47

Test System DK with Large Amounts of Wind Power and High Load

The results of the DK system with large amounts of wind power are presented in Table 9. Even though more wind power is available than for the DK system with medium amounts of wind power, there is now also an increased load, and apparently the extra wind power is not sufficient compensation; hence, the mean spot price is higher and so is the risk of power deficit. The extra wind power is also causing much larger regulation fees than for the previous system.

Again, the impact of the trading arrangements is similar to what we have already seen. The importance of the trading arrangements is on the same scale as for the SE system with large amounts of wind power. The down-regulation fees decreases by more than 20% when the planning horizon is shortened, and the up-regulation fees decrease by more than 35%! The impact on the risk of power deficit is also significant, and flexible consumers will have to accept a lot of activated load reductions (or the load reductions have to be distributed over a large group of consumers as discussed above).

Table 9 *Overview of the results for test system DK with large amounts of wind power and high load.*

Intra-day trading	Wind power as negative load	Flexible consum-ers	Spot price [¤/MWh]	Down-regulation fee [¤/MWh]	Up-regulation fee [¤/MWh]	Risk of power deficit [%]	Probability of load reduction [%]
			36.38	4.52	6.02	1.38	—
✓			36.26	3.11	3.50	0.91	—
	✓		36.38	4.52	6.02	1.38	—
✓	✓		36.26	3.11	3.50	0.91	—
		✓	36.38	5.96	5.84	0.67	1.54
✓		✓	36.26	4.60	3.35	0.20	1.52
	✓	✓	36.38	5.96	5.84	0.67	1.54
✓	✓	✓	36.26	4.60	3.35	0.20	1.52

4.2.2 Players' Surplus

Besides the general market indices concerning price and reliability, the model also provides information of the surplus ($BRPS$) of all balance responsible players. However, it must be noted that the surplus obtained from a simulation only considers *variable* costs. In order to make a profit, the expected surplus per hour has to be sufficient to cover the fixed costs of the balance responsible player, i.e., $8\,760 \cdot BRPS \geq \textit{annual fixed costs}$. Hence, the importance of a small change of $BRPS$ depend on the fixed costs; if the $BRPS$ is just enough to cover the costs then a small change in $BRPS$ can result in a large change of the profits of the player. On the other hand, if the player is already making a large profit then a small change in $BRPS$ will not affect the total profitability that much.

It is not possible to provide realistic data about the fixed costs of the balance responsible players in the test systems. The reason for studying the surplus of the players is to illustrate the importance of different conditions with respect to production resources and amount of demand. Therefore, it is left to the reader to decide whether a small change of $BRPS$ is important or not.

Favourable Trading Arrangements

Let us start by identifying the most favourable trading arrangements for each type of balance responsible player. Table 10 shows how the trading arrangements would affect the surplus for different types of balance responsible players. The judgements are compiled from Table 17 to Table 21 in appendix C.

***Table 10** Benefits of trading arrangements for different balance responsible players.*

Balance responsible player	Independent wind power producer	Independent retailer	Small utility	Large Utility	Peak power producer
Intra-day trading	+	+	+	+	–
Wind power as negative load	+	0	(+)	(+)	0
Flexible consumers	(+)	+	+	+	+

\+ Favourable
(+) Slightly favourable
0 Indifferent
– Not favourable

It can be seen that intra-day trading is beneficial to all balance responsible players but the peak power producers. This is not very surprising, as the planning horizon lowers the regulation fees, which directly affect the imbalance costs. However, peak power producers rarely have any imbalances, and are making a significant share of their profits from the real-time trading; hence, for these players, lower regulation fees means less surplus. It might be noted that large utilities are also active in the real-time trading, but apparently, the reduced imbalance costs due to lower regulation fees are larger than the lost profit from real-time trading.

Whether wind power is considered as generation or negative load only has a direct impact on the surplus of those players who operate wind power (independent wind power producers, small utilities and large utilities) as this trading arrangements only concerns the post market and does not influence neither spot market prices nor real-time balancing market prices. The impact of this trading arrangement is however quite small, especially for the small and large utilities which also are balance responsible for other generation sources as well as consumption.

Introduction of flexible consumer contracts is also beneficial to all players. For players that are balance responsible for consumption (i.e., retailers, small and large utilities) the obvious advantage is that they can reduce the amount that they have to buy at a high price from the spot market (or in case of large utilities, which are net sellers, increase the amount that they can sell at a high price in the spot market). For example, if a player has a forecasted load of 1 000 MWh/h and the spot price is expected to be 70 ¤/MWh, whereas the consumer price is 35 ¤/MWh, the player will make a loss of 35 000 ¤ for this trading period. If activating the flexible consumption reduces the load by 100 MW, the player will buy 900 MW and the spot price might decrease a little bit, which will reduce the losses by more than 10%. The impact on the flexible consumption on imbalance costs is also beneficial, even though the down-regulation fee is increasing; if there was no flexible consumption, power deficit would be more frequent, and balance responsible players with a negative imbalance would then have to pay the artificial imbalance price. Apparently, the risk of the a negative imbalance price of 2 000 ¤/MWh is worse than an increased risk of facing extreme down-regulation fees around

100 ¤/MWh. It can though be noted that for independent wind power producers the benefit in imbalance costs is very small, because they are not balance responsible for any consumption and will therefore not gain any reduced price risk. Peak power producers are also not gaining any reduced price risk, and are generally not having much problems keeping their balance. In this case, the benefit from the flexible consumption is most likely the increased down-regulation fees, which increase the profitability of being active in the real-time balancing market.

Importance of the Trading Arrangements

Assume that the most favourable trading arrangements for a balance responsible player are applied to the electricity market. The question is then how beneficial is this compared to if default trading arrangements (i.e., day-ahead spot market, wind power is accounted as production in the post market and low consumption flexibility) had been used. Table 11 provides an overview of how much larger $BRPS$ different balance responsible players would obtain from the most favourable trading arrangements. The increase is expressed as a percentage of the surplus for that player under default trading arrangements. The exact values and more details about the results for each player and all test systems are found in appendix C.

***Table 11** Increase of $BRPS$ for most favourable trading arrangements compared to default trading arrangements.*

Balance responsible player	Independent wind power producer	Independent retailer	Small utility	Large Utility	Peak power producer
SE, small amount of wind power, low load	2	9–12	5–8	< 1	23–79
SE, medium amount of wind power, low load	3	3	2–4	< 1	24–77
SE, large amount of wind power, low load	9	> 100	14–22	2	21–58
DK, medium amount of wind power, low load	6	11–13	7–9	< 1	15–64
DK, large amount of wind power, low load	49	28–51	58–75	2–5	13–39

The results show that the significance of the trading arrangements is varying a lot between different groups of balance responsible players. It is also noticeable that the increase of the surplus can vary a lot between the test systems for the same group of balance responsible players. However, the trend is that the tougher the market conditions, the larger the importance of the trading arrangements.

For wind power producers, tough market conditions mean high up- and down-regulation fees. By comparing Table 11 with Table 5 to Table 9, we can see that the impact of the most favourable trading arrangements is higher for test systems with high regulation fees. Although the regulation fees are more about two to three times higher in test system DK with large amounts of wind power compared to the SE system with large amounts of wind, the increased surplus of the wind power producers is more than five times as high., which indicates that there is some kind of threshold where imbalance costs become very sensitive to further increase in the imbalance fees.

The main concern of the independent retailers is the price risk, which can be seen by comparing the SE systems with small and medium amounts of wind power respectively. In the latter system, the regulation fees are higher, but the difference between mean spot price and consumer price is higher. Hence, it can be concluded that the risk of facing large imbalance costs is not as important as the risk of having to buy power at a spot price which is higher than the fixed price paid by the consumers. It can also be seen that in the systems with large amounts of wind power and high load, the difference is decreased to a point where the retailers barely make a profit or even become unprofitable, in which case the trading arrangements of course will have a very large impact expressed in per cent of the surplus.

The small utilities show similar characteristics as both wind power producers and retailers, which is not surprising as these players have a quite significant share of wind power in their generation portfolio, while they at the same time act as net buyers in the spot market.

The large utilities are almost indifferent to the trading arrangements in all the test systems, which is explained by the diversification of these players. Increased amounts of wind power will cause the imbalance costs of the large utilities to increase, but they will at the same time make a larger surplus from their participation in the real-time balancing market.

The conditions for peak power producers are quite different from the other players. The problem for these players is that their bids are rarely accepted neither in the spot market nor the real-time balancing market. Therefore, trading arrangements are less important in the test systems with high mean spot prices and with large forecast errors. It should also be noted that there are large differences within the group. Peak power producer 1, which operates a power plant with a variable operation cost of 70 ¤/MWh gains relatively less from the most favourable trading arrangements compared to peak power producer 5, which operates a power plant with the variable operation cost 90 ¤/MWh.

4.3 Sensitivity Analysis

The model used in this work includes a wide range of parameters. The test systems in the case study have illustrated the consequences of varying some main parameters considering installed capacity, generation and regulation costs, forecast errors, etc. However, there could of course be other factors that influence the importance of the choice of trading arrangements in an electricity market. This section provides a short sensitivity analysis concerning wind power correlation and load reduction forecasts.

Correlation of Wind Power

As described in section 3.1.4, the wind power general model consists of a component which is shared by all balance responsible player, and one component that is independent for all players. By varying the relative size of these two components, it is possible to vary the correlation between the wind power generation and the wind power forecast errors of different players.

The results in section 4.2 are based on a model where the shared component is much larger then the independent component, which means that forecast errors as well as available generation in the real-time phase have a very strong positive correlation (almost 100%) between different players. However, the benefit of a one-price system for imbalance pricing is that a player who has an imbalance that is helping the system will receive a favourable price. In order to help the system, a player should have an imbalance in the opposite direction compared to the majority of the other players. Since wind power forecast errors is a dominant source of imbalances, it is then quite unlikely that a wind power producer will have an imbalance in the opposite direction; thus, the benefits of using a one-price system for wind power imbalances might be underestimated.

To investigate the importance of correlations in wind power generation, the same test systems as before were simulated once more, but with no correlations at all between wind power forecasts and real wind power outcome of different balance responsible players. An important consequence of the independence is that the amount of wind power that is available in the system in a given situation will be smoother. This means that the spot prices will decrease slightly, the regulation fees will be substantially smaller in the systems with medium or large amounts of wind power, and there will also be a lower risk of power deficit (cf. Table 12). Hence, the balance responsible players will face lesser risks, and as concluded in section 4.2.2 the trading arrangements will be less important.

Table 13 shows the size of the increase of $BRPS$ for the most favourable trading arrangements when the test systems are simulated with independent wind power. It is difficult to make a direct comparison between the results for dependent wind power (see Table 11), but there is nothing in the results indicating that the assumption of independent wind power makes a one-price system for wind power imbalances much more beneficial. This is clearly visible, in the SE system with small amounts of wind, where the prices and reliability are more or less the same in both cases; here, the benefit of the most favourable trading arrangements is in the same size of order as before. For the other systems, the importance of favourable trading arrangements seems to be smaller, but this is as mentioned above due to the lesser risks. If systems were created with dependent wind but exactly the same mean spot price and regulation fees as for the independent wind power test systems, the benefit of favourable trading arrangements would probably be slightly higher in the latter systems.

***Table 12** Comparison of system indices for dependent and independent wind power under default trading arrangements.*

Test system	Spot price [¤/MWh]	Down-regulation fee [¤/MWh]	Up-regulation fee [¤/MWh]	Risk of power deficit [%]
SE, small amounts of wind power, low load				
Dependent wind power	29,30	1,98	1,35	0,18
Independent wind power	29,29	1,98	1,33	0,18
SE, medium amounts of wind power, low load				
Dependent wind power	27,66	2,51	1,58	0,13
Independent wind power	27,65	2,17	1,30	0,10
SE, large amounts of wind power, high load				
Dependent wind power	30,09	3,68	2,59	0,59
Independent wind power	29,84	2,83	1,83	0,42
DK, medium amounts of wind power, low load				
Dependent wind power	33,36	2,76	3,16	0,27
Independent wind power	33,21	2,17	2,34	0,24
DK, large amounts of wind power, low load				
Dependent wind power	36,38	4,52	6,02	1,38
Independent wind power	35,66	3,23	3,59	0,71

***Table 13** Overview of the importance of the trading arrangements for different balance responsible players if wind power is independent.*

Balance responsible player	Independent wind power producer	Independent retailer	Small utility	Large Utility	Peak power producer
SE, small amount of wind power, low load	1–2	10	5–8	< 1	25–84
SE, medium amount of wind power, low load	1	3	2–4	< 1	25–108
SE, large amount of wind power, low load	2	63–159	5–14	1–2	26–68
DK, medium amount of wind power, low load	1–2	10–11	5–10	< 1	17–63
DK, large amount of wind power, low load	3	39–95	14–28	1	20–57

Load Reduction Forecast Errors

The uncertainty of the size of the load reduction for flexible consumers may depend on how the flexibility is implemented. For example, if the retailers have equipment for remote control of the consumers' load then there might not be any uncertainty at all. On the other hand, if the load reduction is depending on the actions of the consumers, there might be a considerable uncertainty whether the consumer will bother or not. It can therefore be interesting to investigate if the results presented in section 4.2 are sensitive to the load forecast uncertainty.

In this sensitivity analysis, the results from the simulations in section 4.2 are compared to a model where the retailers have perfect information about size of the load reduction and a model where the forecast errors of the retailers are significantly larger (see Figure 13). However, new simulations using these two alternative models provide more or less exactly the same results as the base. Hence, it seems as if it is the consumption flexibility in itself that affects the electricity market, and that the load reduction uncertainty has only a very small impact.

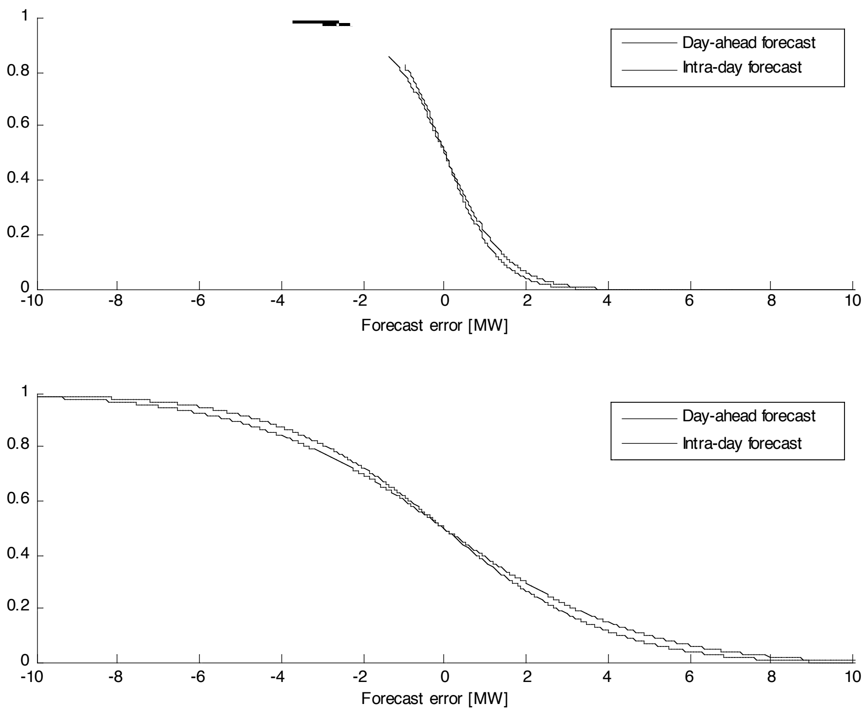

Figure 13 *Load reduction forecast errors for a retailer with a base load of 100 MW. The upper panel shows the forecast errors for the model used in section 4.2 and the lower panel shows the forecast errors for significantly larger forecast errors used in the sensitivity analysis. The load reduction forecast errors should be compared to the average load reduction (10% of the base load, i.e., 10 MW).*

5 Conclusions

This report has presented the findings of a study of the impact of electricity market trading arrangements on systems with large amounts of wind power and flexible consumers. The main results are a new electricity market model and a case study of fictitious test systems with the same basic characteristics as found in the Nordic electricity market.

5.1 Simulation Model

An electricity market model suitable for simulation of different trading arrangements in electricity market has been presented in chapter 3. The model is used in a Monte Carlo simulation using correlated sampling, which increases the accuracy when comparing alternative trading arrangements for a specific system.

The random inputs to the model are forecasted and real available generation capacity, forecasted and real load and forecasted and real load reduction of flexible consumers during high price periods. Procedures to acquire the probability distribution of these random variables have been presented. In combination with data about generation costs, up- and down-regulation costs, etc., the model simulates each step of the electricity trading procedure by compiling the appropriate supply and demand curves, and calculates the resulting prices.

The advantage of the model presented here is that since prices are always based on supply and demand, the model can be applied to systems for which there are no historical data of spot prices, up- and down regulation fees, etc. However, this also means that a lot more data is necessary to set up a simulation model of a system.

5.2 Trading Arrangements

The case study in this report has shown that there are potential benefits of changing the trading arrangements in an electricity market. However, the impact can vary substantially depending on the conditions on the electricity market. Moreover, it has also been shown that the value of changing the trading arrangement will not be the same for all balance responsible players, but will depend on the nature of the costs and the amount of risk that the player is subject to. Hence, it is important to carefully consider the pros and cons of suggested design of the trading arrangements in order to make sure that the electricity market is achieving the objectives that are considered appropriate.

The focus of this report has not been to collect and compile all the data that is necessary to make accurate estimates of the value of introducing specific trading arrangements. Moreover, the costs of changing the trading arrangements have not been investigated here. Thus, at this point it is not possible to provide an optimal design of the trading arrangements in the

Nordic electricity market. However, the case study has illustrated trends and principles, which give some indications on the importance of different actions.

Planning Horizon

The conclusion from the case study was that all players except peak power producers will benefit from a shorter planning horizon. A shorter planning horizon may also result in an increased reliability of supply provided that the planning horizon still is long enough to allow thermal power plants with long start-up times to be active in the spot market.

In the Nordic electricity market, a shorter planning horizon can be achieved by introducing more gate closures per day. For example, bids for delivery in the morning (12 midnight to 12 noon) could be submitted at 9 pm. on the day before, and bids for delivery in the evening (12 noon to 12 midnight) could be submitted at 9 am. on the same day. This means that forecasts have to be prepared between 3 and 15 hours prior to the trading period. Another alternative would be to have four gate closures at for example 6 am. (delivery between 9 am. and 3 pm.), 12 noon (delivery between 3 pm. and 9 pm.), 6 pm. (delivery between 9 pm. and 3 am.) and 12 midnight (delivery between 3 am. and 9 am.), which would require forecasts between 3 and 9 hours prior to the trading period. Yet another option, is that the players voluntarily moves more of the trading from the spot market, Elspot, to the adjustment market Elbas, which has a planning horizon of just one hour. In the latter case, the pricing scheme of Elbas could be changed from pay-as-bid to a price cross.

Shorter planning horizons will of course come at a price, as the players participating in the trading at the power exchange will need more staff working round the clock. Another disadvantage is that the income for peak power units will decrease, since participation in the real-time balancing market generates a substantial income for these units, and this income is of course decreased if the system operator does not have to activate as many bids to the real-time balancing market. Hence, in the short run, the shorter planning horizon might result in more efficient usage of the generation resources and improved reliability, but in the long run, peak power units might be shut down resulting in worsened reliability. On the other hand, it has been suggested that increased consumer flexibility can be a more cost-efficient method to maintain a low risk of power deficit [10]; the effectiveness of flexible consumption has also been illustrated by the case study in this report.

The question will therefore be if the benefits are larger than the extra costs and possible consequences for the reliability of supply. This requires further studies of how the forecast errors of wind power in the Nordic countries would decrease for the lower planning horizons mentioned above in combination with the possible improvements of the forecasts tools that might come with a large-scale introduction of wind power.

Pricing of Wind Power Imbalances

The results of thecase study has shown that the imbalance costs of wind power are quite small compared to the income from sales in the spot market. Similar results have also been observed in for example [8]. If wind power producers receive some form of generation-based support (such as for example the Swedish “elcertifikat” system) then imbalance costs will constitute an even smaller share of the total turnover. Hence, it is not surprising that reducing the imbalance costs by applying a one-price system for wind power imbalances, will not have a major impact on the surplus of wind power producers, unless they are facing really large regulation fees (as in the test systems with large amounts of wind power). However, as explained in section 4.2.2, a small change in surplus can still be very important if a player has high fixed costs in relation to the surplus. This could very well be the case for wind power, since wind generators have high investment costs and low variable costs.

Introducing a one-price system for wind power can for example be done by considering wind power as negative load in the consumption imbalance (as in the case study) or by dividing the production imbalance into a dispatchable units imbalance and another imbalance for non-dispatchable units. Either way, the change in imbalance pricing for wind power would not cause any direct costs for other players in the electricity market, since the imbalance pricing does not affect spot market and real-time balancing market prices. However, less imbalance costs for wind power producers means less income for the system operator; some other tariffs must then be increased if the system operator is to maintain its economic performance, and that might of course affect all players.

Whether or not it is advisable to introduce a one-price system for wind power imbalances is therefore an open question. However, it can be observed that in the case study, the results for the trading arrangements that is the most favourable to wind power producers (intra-day trading, wind power as negative load and flexible consumption) is not much better–the difference is about 0.5%–than the second best option (intra-day trading, wind power included in the ordinary production and flexible consumption). This could be an indication that the imbalance costs might not be crucial for wind power producers, and that other aspects of the trading arrangements are more important.

Flexible Consumption

This report has investigated a special form of flexible consumption, where the consumers normally do not respond to prices in the spot market, but the retailers have the possibility to prompt a load reduction for a limited number of hours per year. This kind of flexibility can be achieved in several ways, ranging from simple solutions as sending a text message to the mobile phone of the customer, to installing equipment that allows the retailer to remotely control the load of customer.

The results from the case study have shown that these kinds of contracts have a clear value for all kind of players. The question is therefore only if the costs for the necessary infrastructure are low enough. To investigate this, the costs of different technical solutions must be further evaluated, and there is also a need to study how large load reduction each solution will give in the long run – it might be worthwhile to invest in remote control compared to more simple solutions if it turns out that the consumers after a while pays less attention to the signals from the retailer.

5.3 Future Work

The model which has been presented in this report is quite versatile. In fact, not all features introduced in the model have been used in the case studies presented in chapter 4 (for example, only one real-time market phase was used). Nevertheless, there are of course possibilities to improve the model even further. It would also be interesting to use the model for other case studies.

5.3.1 Model Development

A limitation with the simulation method is that the computation time is quite significant. In the case study it was necessary to use 100 000 samples to get accurate results, which resulted in a computation time of several hours. It would therefore be interesting to study if other variance reduction techniques besides correlated sampling could be used to shorten this time.

An improvement of the actual trading model would be to consider transmission limitations and the possibility to have different prices (in the ahead trading as well as the real-time trading) for different areas. This can quite easily be achieved by replacing the optimisation problems (8), (20) and (26) by their multi-area counterparts (cf. [5], chapters 3 and 6). The challenge with a multi-area approach will of course be that even more data has to be collected.

Another improvement would be to develop the modelling of hydro power. In this report, hydro power generation is bidding according to a water value, which is assumed to be constant and known in advance for each hydro power plant, i.e., the hydro power plants have been modelled in the same way as thermal power plants. In reality, water values are subject to uncertainty and correlated to the demand and the availability of other generation sources. A possible modification of the model would be to allow the water values to be random variables. The probability distribution of the water values could be obtained using a traditional hydro power planning tool as for example the EMPS model developed by Sintef in Norway. Another option would be to let each scenario include more than one trading period, but that would drastically increase the complexity of the model and probably lead to unacceptably long execution times of the Monte Carlo simulation part (cf. [4], chapter 10).

5.3.2 Additional Case Studies

Many of the data used in the case study of this report are based on rough estimates or conjecture. Thus, it would of course be interesting to repeat the same kind of case study with more accurate data, for example concerning forecast errors in wind power and consumption for different planning horizons, correlations between wind power and load, etc.

The model could also be used to study how prices are affected for different degrees of participation in the available market phases of the ahead market (i.e., spot market and adjustment market). In this report, it was assumed that all ahead trading was performed in a spot market; it would be interesting to compare this to an electricity market where each phase has around 50% of the turnover.

A Root Mean Square Error

In scientific literature, several statistical measures are used to describe the size of forecast errors. This appendix provides definitions of the root mean square error.

In this report, the forecast error is defined as the difference between the predicted value and the actual value, i.e.,

$$forecast\ error = forecast - real\ outcome. \tag{36}$$

With this definition, negative forecast errors indicate that the forecast underestimated the real outcome, whereas positive values indicate that the forecast overestimated the real outcome.

To get an idea about the size of the forecast errors it is not useful to study the mean value (which should be zero unless there is some bias in the forecast tool). A common measure is therefore to study the Root Mean Square Error, which is defined as

$$RMSE = \sqrt{\frac{1}{n}\sum_{i=1}^{n}(forecast\ error_i)^2}. \tag{37}$$

To simplify comparison, the RMSE can be normalised. The so-called Normalised Root Mean Square Error is defined as

$$NRMSE = \frac{RMSE}{maximal\ outcome - minimal\ outcome}. \tag{38}$$

The NRMSE value is useful for predictions that have a well-defined minimum and maximum value. If that is not the case, it is possible to normalise by the mean outcome. This measure is referred to as coefficient of variation of the root mean square error:

$$CV\text{-}RMSE = \frac{RMSE}{mean\ outcome}. \tag{39}$$

B Simulation Data

This appendix provides further data about the balance responsible players in the case study described in chapter 4.

Table 14 *Installed capacity of the balance responsible players in test system SE*

Player	Amount of wind power	Installed capacity [MW] Wind power	Conventional
Wind 1	Small	25	–
Wind 1	Medium	50	–
Wind 1	Large	100	–
Wind 2	Small	50	–
Wind 2	Medium	100	–
Wind 2	Large	200	–
Wind 3	Medium	50	–
Wind 3	Large	100	–
Wind 4	Medium	100	–
Wind 4	Large	200	–
Wind 5	Medium	50	–
Wind 5	Large	100	–
Wind 6	Medium	150	–
Wind 6	Large	300	–
Small utility 1	Small	50	250
Small utility 1	Medium	100	250
Small utility 1	Large	200	250
Small utility 2	Small	75	250
Small utility 2	Medium	200	250
Small utility 2	Large	400	250
Large utility 1	Small	50	8 250
Large utility 1	Medium	600	8 250
Large utility 1	Large	1 200	8 250
Large utility 2	Small	100	8 250
Large utility 2	Medium	800	8 250
Large utility 2	Large	1 600	8 250
Peak power 1		–	20
Peak power 2		–	20
Peak power 3		–	20
Peak power 4		–	20
Peak power 5		–	20

Table 15 *Installed capacity of the balance responsible players in test system DK*

Player	Amount of wind power	Installed capacity [MW] Wind power	Conventional
Wind 1	Medium	75	–
Wind 1	Large	150	–
Wind 2	Medium	150	–
Wind 2	Large	300	–
Wind 3	Medium	75	–
Wind 3	Large	150	–
Wind 4	Medium	150	–
Wind 4	Large	300	–
Wind 5	Medium	75	–
Wind 5	Large	150	–
Wind 6	Medium	225	–
Wind 6	Large	450	–
Small utility 1	Medium	150	250
Small utility 1	Large	300	250
Small utility 2	Medium	300	250
Small utility 2	Large	600	250
Large utility 1	Medium	600	7 750
Large utility 1	Large	1 200	7 750
Large utility 2	Medium	1 200	7 750
Large utility 2	Large	2 400	7 750
Peak power 1		–	20
Peak power 2		–	20
Peak power 3		–	20
Peak power 4		–	20
Peak power 5		–	20

Table 16 *Mean load of the balance responsible players*

Player	Load level	Mean load [MW]
Retailer 1	Low	1 000
Retailer 1	High	1 100
Retailer 2	Low	2 000
Retailer 2	High	2 200
Small utility 1	Low	400
Small utility 1	High	450
Small utility 2	Low	600
Small utility 2	High	650
Large utility 1	Low	3 000
Large utility 1	High	3 300
Large utility 2	Low	3 000
Large utility 2	High	3 300

C Simulation Results

This appendix lists details about the surplus of the balance responsible players in the case study described in chapter 4. The tables shows all balance responsible players that have been defined for each test system, and how their surplus (*BRPS*) is affected by different trading arrangements.

The absolute value of *BRPS* (expressed in ¤/h) is only given for the default trading arrangements (i.e., day-ahead trading, wind power as generation and no extra consumption flexibility). For the other trading arrangements, the values indicate the change compared to the default trading arrangements. The changes are given both in ¤/h and in %. The abbreviation "negl." is used in those cases where there is a change, but it is so small that it is negligible.

It can be noted that thanks to the usage of correlated sampling, the differences can be directly compared. This means that if trading arrangement A results in an increase of 10 ¤/h compared to default trading arrangements, and trading arrangements B results in an increase of 15 ¤/h, then it is possible to conclude that the surplus would increase by 5 ¤/h when switching from trading arrangement A to trading arrangement B.[6]

[6] This might seem trivial, but such a comparison is not possible in a Monte Carlo simulation using simple sampling.

Table 17 *Results for the balance responsible players in test system SE with small amounts of wind power and low load..*

Player	Trading arrangement							
	No extra consumption flexibility				Extra consumption flexibility			
	Wind power as generation		Wind power as negative load		Wind power as generation		Wind power as negative load	
	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading
Wind 1	185	+1.8 (+1.0%)	+2.0 (+1.1%)	+2.7 (+1.4%)	+0.4 (+0.2%)	+1.9 (+1.0%)	+2.1 (+1.2%)	+2.8 (+1.5%)
Wind 2	370	+3.5 (+0.9%)	+4.1 (+1.1%)	+5.4 (+1.5%)	+0.9 (+0.2%)	+3.8 (+1.0%)	+4.3 (+1.2%)	+5.6 (+1.5%)
Retailer 1	1 433	+51 (+3.6%)	±0	+51 (+3.6%)	+98 (+6.8%)	+139 (+9.7%)	+98 (+6.8%)	+139 (+9.7%)
Retailer 2	2 297	+83 (+3.6%)	±0	+83 (+3.6%)	+200 (+8.7%)	+266 (+11.6%)	+200 (+8.7%)	+266 (+11.6%)
Small utility 1	2 256	+86 (+3.8%)	+4 (+0.2%)	+89 (+3.9%)	+161 (+7.2%)	+174 (+7.7%)	+165 (+7.3%)	+176 (+7.8%)
Small utility 2	2 735	+68 (+2.5%)	+6 (+0.2%)	+71 (+2.6%)	+106 (+3.9%)	+142 (+5.2%)	+111 (+4.1%)	+145 (+5.3%)
Large utility 1	79 294	+216 (+0.3%)	+4 (negl.)	+218 (+0.3%)	+424 (+0.5%)	+575 (+0.7%)	+427 (+0.5%)	+578 (+0.7%)
Large utility 2	79 614	+250 (+0.3%)	+7 (negl.)	+254 (+0.3%)	+439 (+0.6%)	+623 (+0.8%)	+445 (+0.6%)	+627 (+0.8%)
Peak power 1	11.1	−0.8 (−7.1%)	±0	−0.8 (−7.1%)	+2.6 (+23.8%)	+1.8 (+16.1%)	+2.6 (+23.8%)	+1.8 (+16.1%)
Peak power 2	9.6	−0.7 (−7.1%)	±0	−0.7 (−7.1%)	+3.0 (+31.3%)	+2.3 (+23.8%)	+3.0 (+31.3%)	+2.3 (+23.8%)
Peak power 3	8.0	−0.6 (−8.1%)	±0	−0.6 (−8.1%)	+3.4 (+42.6%)	+2.7 (+34.1%)	+3.4 (+42.6%)	+2.7 (+34.1%)
Peak power 4	6.4	−0.7 (−10.8%)	±0	−0.7 (−10.8%)	+3.7 (+57.9%)	+3.0 (+47.5%)	+3.7 (+57.9%)	+3.0 (+47.5%)
Peak power 5	5.3	−0.5 (−9.6%)	±0	−0.5 (−9.6%)	+4.2 (+78.6%)	+3.6 (+67.4%)	+4.2 (+78.6%)	+3.6 (+67.4%)

Table 18 *Results for the balance responsible players in test system SE with medium amounts of wind power and low load.*

Player	Trading arrangement							
	No extra consumption flexibility				Extra consumption flexibility			
	Wind power as generation		Wind power as negative load		Wind power as generation		Wind power as negative load	
	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading
Wind 1	329	+9.0 (+2.7%)	+1.3 (+0.4%)	+9.8 (+3.0%)	+1.0 (+0.3%)	+9.5 (+2.9%)	+2.1 (+0.6%)	+10.3 (+3.1%)
Wind 2	658	+18.0 (+2.7%)	+2.7 (+0.4%)	+19.7 (+3.0%)	+1.8 (+0.3%)	+18.8 (+2.9%)	+4.0 (+0.6%)	+20.5 (+3.1%)
Wind 3	329	+9.1 (+2.8%)	+1.4 (+0.4%)	+9.9 (+3.0%)	+1.1 (+0.3%)	+9.6 (+2.9%)	+2.2 (+0.7%)	+10.4 (+3.2%)
Wind 4	658	+18.3 (+2.8%)	+2.7 (+0.4%)	+20.0 (+3.0%)	+2.3 (+0.3%)	+19.4 (+2.9%)	+4.5 (+0.7%)	+21.1 (+3.2%)
Wind 5	329	+9.0 (+2.7%)	+1.4 (+0.4%)	+9.8 (+3.0%)	+1.0 (+0.3%)	+9.5 (+2.9%)	+2.1 (+0.6%)	+10.3 (+3.1%)
Wind 6	987	+26.6 (+2.7%)	+4.0 (+0.4%)	+29.2 (+3.0%)	+2.9 (+0.3%)	+28.0 (+2.8%)	+6.2 (+0.6%)	+30.6 (+3.1%)
Retailer 1	3 223	+32 (+1.0%)	±0	+32 (+1.0%)	+59 (+1.8%)	+84 (+2.6%)	+59 (+1.8%)	+84 (+2.6%)
Retailer 2	5 899	+66 (+1.1%)	±0	+66 (+1.1%)	+136 (+2.3%)	+191 (+3.2%)	+136 (+2.3%)	+191 (+3.2%)
Small utility 1	3 043	+53 (+1.7%)	+3 (+0.1%)	+54 (+1.8%)	+86 (+2.8%)	+113 (+3.7%)	+89 (+2.9%)	+115 (+3.8%)
Small utility 2	4 349	+56 (+1.3%)	+6 (+0.1%)	+59 (+1.4%)	+62 (+1.4%)	+108 (+2.5%)	+67 (+1.5%)	+112 (+2.6%)
Large utility 1	80 228	+182 (+0.2%)	+15 (negl.)	+192 (+0.2%)	+279 (+0.3%)	+429 (+0.5%)	+291 (+0.4%)	+440 (+0.5%)
Large utility 2	81 499	+191 (+0.2%)	+19 (negl.)	+205 (+0.3%)	+300 (+0.4%)	+455 (+0.6%)	+316 (+0.4%)	+469 (+0.6%)
Peak power 1	7.4	−0.5 (−6.4%)	±0	−0.5 (−6.4%)	+1.8 (+24.5%)	+1.3 (+17.7%)	+1.8 (+24.5%)	+1.3 (+17.7%)
Peak power 2	6.4	−0.5 (−7.3%)	±0	−0.5 (−7.3%)	+2.0 (+30.9%)	+1.6 (+24.2%)	+2.0 (+30.9%)	+1.6 (+24.2%)
Peak power 3	5.0	−0.1 (−2.6%)	±0	−0.1 (−2.6%)	+2.6 (+52.6%)	+2.1 (+42.2%)	+2.6 (+52.6%)	+2.1 (+42.2%)
Peak power 4	4.3	−0.4 (−10.2%)	±0	−0.4 (−10.2%)	+2.5 (+58.4%)	+2.0 (+47.6%)	+2.5 (+58.4%)	+2.0 (+47.6%)
Peak power 5	3.6	−0.4 (−11.9%)	±0	−0.4 (−11.9%)	+2.7 (+76.3%)	+2.3 (+64.1%)	+2.7 (+76.3%)	+2.3 (+64.1%)

Table 19 *Results for the balance responsible players in test system SE with large amounts of wind power and high load.*

Player	Trading arrangement							
	No extra consumption flexibility				Extra consumption flexibility			
	Wind power as generation		Wind power as negative load		Wind power as generation		Wind power as negative load	
	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading
Wind 1	631	+54 (+8.5%)	+4 (+0.6%)	+56 (+8.8%)	+9 (+1.5%)	+57 (+9.0%)	+12 (+1.9%)	+59 (+9.4%)
Wind 2	1 263	+106 (+8.4%)	+8 (+0.6%)	+111 (+8.8%)	+18 (+1.5%)	+113 (+8.9%)	+24 (+1.9%)	+117 (+9.3%)
Wind 3	632	+53 (+8.4%)	+4 (+0.6%)	+56 (+8.8%)	+9 (+1.5%)	+56 (+8.9%)	+12 (+1.9%)	+58 (+9.2%)
Wind 4	1 263	+107 (+8.5%)	+7 (+0.6%)	+111 (+8.8%)	+19 (+1.5%)	+113 (+8.9%)	+24 (+1.9%)	+117 (+9.3%)
Wind 5	632	+53 (+8.4%)	+4 (+0.6%)	+56 (+8.8%)	+9 (+1.5%)	+56 (+8.9%)	+12 (+1.9%)	+58 (+9.3%)
Wind 6	1 894	+159 (+8.4%)	+11 (+0.6%)	+165 (+8.7%)	+28 (+1.5%)	+169 (+8.9%)	+36 (+1.9%)	+176 (+9.3%)
Retailer 1	168	+149 (+89%)	±0	+149 (+89%)	+271 (+161%)	+367 (+218%)	+271 (+161%)	+367 (+218%)
Retailer 2	–463	+192 (+42%)	±0	+192 (+42%)	+458 (+99%)	+639 (+138%)	+458 (+99%)	+639 (+138%)
Small utility 1	2 860	+336 (+11.8%)	+8 (+0.3%)	+341 (+11.9%)	+490 (+17.1%)	+610 (+21.3%)	+497 (+17.4%)	+615 (+21.5%)
Small utility 2	4 212	+380 (+9.0%)	+17 (+0.4%)	+389 (+9.2%)	+379 (+9.0%)	+612 (+14.5%)	+391 (+9.3%)	+620 (+14.7%)
Large utility 1	89 699	+656 (+0.7%)	+35 (negl.)	+681 (+0.8%)	+1 075 (+1.2%)	+1 599 (+1.8%)	+1 101 (+1.2%)	+1 622 (+1.8%)
Large utility 2	92 124	+770 (+0.8%)	+44 (negl.)	+805 (+0.9%)	+1 145 (+1.2%)	+1 784 (+1.9%)	+1 176 (+1.3%)	+1 818 (+2.0%)
Peak power 1	25.4	–3.0 (–11.7%)	±0	–3.0 (–11.7%)	+5.6 (+21.9%)	+2.8 (+10.8%)	+5.6 (+21.9%)	+2.8 (+10.8%)
Peak power 2	22.8	–2.8 (–12.4%)	±0	–2.8 (–12.4%)	+6.2 (+27.2%)	+3.7 (+16.3%)	+6.2 (+27.2%)	+3.7 (+16.3%)
Peak power 3	19.2	–2.3 (–11.9%)	±0	–2.3 (–11.9%)	+7.8 (+40.6%)	+5.1 (+26.5%)	+7.8 (+40.6%)	+5.1 (+26.5%)
Peak power 4	16.3	–2.3 (–14.2%)	±0	–2.3 (–14.2%)	+8.2 (+50.0%)	+5.8 (+35.8%)	+8.2 (+50.0%)	+5.8 (+35.8%)
Peak power 5	14.8	–2.7 (–18.0%)	±0	–2.7 (–18.0%)	+8.5 (+57.4%)	+6.4 (+42.9%)	+8.5 (+57.4%)	+6.4 (+42.9%)

***Table 20** Results for the balance responsible players in test system DK with medium amounts of wind power and low load.*

Player	Trading arrangement							
	No extra consumption flexibility				Extra consumption flexibility			
	Wind power as generation		Wind power as negative load		Wind power as generation		Wind power as negative load	
	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading
Wind 1	540	+32 (+5.9%)	+3 (+0.5%)	+33 (+6.1%)	+3 (+0.5%)	+32 (+6.0%)	+5 (+0.9%)	+34 (+6.2%)
Wind 2	1 079	+64 (+5.9%)	+5 (+0.5%)	+67 (+6.2%)	+6 (+0.5%)	+66 (+6.1%)	+10 (+0.9%)	+68 (+6.3%)
Wind 3	540	+32 (+5.8%)	+3 (+0.5%)	+33 (+6.1%)	+3 (+0.5%)	+32 (+6.0%)	+5 (+0.9%)	+34 (+6.3%)
Wind 4	1 080	+64 (+5.9%)	+5 (+0.5%)	+66 (+6.1%)	+6 (+0.5%)	+65 (+6.0%)	+10 (+0.9%)	+68 (+6.3%)
Wind 5	540	+32 (+5.9%)	+3 (+0.5%)	+33 (+6.2%)	+3 (+0.5%)	+33 (+6.0%)	+5 (+0.9%)	+34 (+6.3%)
Wind 6	1 619	+94 (+5.8%)	+8 (+0.5%)	+98 (+6.1%)	+8 (+0.5%)	+97 (+6.0%)	+15 (+0.9%)	+101 (+6.2%)
Retailer 1	2 317	+170 (+7.3%)	±0	+170 (+7.3%)	+107 (+4.6%)	+264 (+11.4%)	+107 (+4.6%)	+264 (+11.4%)
Retailer 2	3 703	+255 (+6.9%)	±0	+255 (+6.9%)	+219 (+5.9)	+457 (+12.3%)	+219 (+5.9)	+457 (+12.3%)
Small utility 1	4 397	+286 (+6.5%)	+6 (+0.1%)	+288 (+6.6%)	+287 (+6.5%)	+405 (+9.2%)	+292 (+6.6%)	+408 (+9.3%)
Small utility 2	5 998	+323 (+5.4%)	+11 (+0.2%)	+328 (+5.5%)	+217 (+3.6%)	+426 (+7.1%)	+226 (+3.8%)	+432 (+7.2%)
Large utility 1	125 688	+154 (+0.1%)	+11 (negl.)	+166 (+0.1%)	+483 (+0.4%)	+576 (+0.5%)	+492 (+0.4%)	+588 (+0.5%)
Large utility 2	130 161	+437 (+0.3%)	+32 (negl.)	+460 (+0.4%)	+512 (+0.4%)	+864 (+0.7%)	+536 (+0.4%)	+887 (+0.7%)
Peak power 1	19.9	−4.7 (−23.5%)	±0	−4.7 (−23.5%)	+3.1 (+15.4%)	−1.7 (−8.7%)	+3.1 (+15.4%)	−1.7 (−8.7%)
Peak power 2	15.9	−3.6 (−22.9%)	±0	−3.6 (−22.9%)	+3.6 (+22.4%)	−0.2 (−1.0%)	+3.6 (+22.4%)	−0.2 (−1.0%)
Peak power 3	11.9	−2.4 (−19.9%)	±0	−2.4 (−19.9%)	+3.9 (+32.5%)	+1.4 (+12.0%)	+3.9 (+32.5%)	+1.4 (+12.0%)
Peak power 4	9.7	−2.0 (−21.2%)	±0	−2.0 (−21.2%)	+4.7 (+48.1%)	+2.2 (+22.4%)	+4.7 (+48.1%)	+2.2 (+22.4%)
Peak power 5	7.9	−1.4 (−18.1%)	±0	−1.4 (−18.1%)	+5.0 (+63.4%)	+3.1 (+39.6%)	+5.0 (+63.4%)	+3.1 (+39.6%)

***Table 21** Results for the balance responsible players in test system DK with large amounts of wind power and high load.*

Player	Trading arrangement							
	No extra consumption flexibility				Extra consumption flexibility			
	Wind power as generation		Wind power as negative load		Wind power as generation		Wind power as negative load	
	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading	Day-ahead trading	Intra-day trading
Wind 1	718	+342 (+47.6%)	+11 (+1.5%)	+345 (+48.1%)	+18 (+2.5%)	+348 (+48.4%)	+24 (+3.3%)	+351 (+48.9%)
Wind 2	1 434	+687 (+47.9%)	+20 (+1.4%)	+694 (+48.3%)	+38 (+2.7%)	+698 (+48.7%)	+49 (+3.4%)	+705 (+49.2%)
Wind 3	719	+341 (+47.4%)	+10 (+1.4%)	+344 (+47.9%)	+18 (+2.5%)	+346 (+48.1%)	+23 (+3.2%)	+350 (+48.6%)
Wind 4	1 434	+685 (+47.7%)	+21 (+1.5%)	+692 (+48.2%)	+37 (+2.6%)	+695 (+48.5%)	+48 (+3.3%)	+703 (+49.0%)
Wind 5	715	+345 (+48.2%)	+10 (+1.5%)	+348 (+48.6%)	+19 (+2.6%)	+350 (+48.9%)	+24 (+3.4%)	+354 (+49.6%)
Wind 6	2 144	+1 035 (+48.3%)	+32 (+1.5%)	+1 046 (+48.8%)	+58 (+2.7%)	+1 052 (+49.1%)	+74 (+3.4%)	+1 063 (+49.6%)
Retailer 1	−1 835	+589 (+32.1%)	±0	+589 (+32.1%)	+369 (+20.1%)	+923 (+50.3%)	+369 (+20.1%)	+923 (+50.3%)
Retailer 2	−4 489	+600 (+13.4%)	±0	+600 (+13.4%)	+663 (+14.8%)	+1 277 (+28.4%)	+663 (+14.8%)	+1 277 (+28.4%)
Small utility 1	3 174	+1 866 (+58.8%)	+21 (+0.7%)	+1 873 (+59.0%)	+1 451 (+45.7%)	+2 369 (+74.6%)	+1 463 (+46.1%)	+2 376 (+74.9%)
Small utility 2	4 625	+2 312 (+50.0%)	+42 (+0.9%)	+2 327 (+50.3%)	+985 (+21.3%)	+2 681 (+57.9%)	+1 007 (+21.8%)	+2 696 (+58.3%)
Large utility 1	134 614	+2 259 (+1.7%)	+56 (negl.)	+2 286 (+1.7%)	+1 611 (+1.2%)	+3 701 (+2.7%)	+1 633 (+1.2%)	+3 732 (+2.8%)
Large utility 2	140 482	+5 031 (+3.6%)	+134 (+0.1%)	+5 081 (+3.6%)	+1 769 (+1.3%)	+6 546 (+4.7%)	+1 827 (+1.3%)	+6 602 (+4.7%)
Peak power 1	65.1	−20.1 (−30.9%)	±0	−20.1 (−30.9%)	+9.0 (+13.9%)	−11.1 (−17.1%)	+9.0 (+13.9%)	−11.1 (−17.1%)
Peak power 2	56.2	−17.8 (−31.6%)	±0	−17.8 (−31.6%)	+10.6 (+18.9%)	−7.5 (−13.3%)	+10.6 (+18.9%)	−7.5 (−13.3%)
Peak power 3	46.8	−14.5 (−30.9%)	±0	−14.5 (−30.9%)	+12.3 (+26.3%)	−3.0 (−6.4%)	+12.3 (+26.3%)	−3.0 (−6.4%)
Peak power 4	41.5	−13.9 (−33.5%)	±0	−13.9 (−33.5%)	+12.6 (+30.4%)	−1.2 (−2.9%)	+12.6 (+30.4%)	−1.2 (−2.9%)
Peak power 5	36.3	−12.1 (−33.3)	±0	−12.1 (−33.3)	+14.2 (+39.0%)	+1.6 (+4.5%)	+14.2 (+39.0%)	+1.6 (+4.5%)

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