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Integration of Regulating Power Markets in Northern Europe

Thesis for the degree of Philosophiae Doctor

Trondheim, July 2012

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Preface

The presented research was carried out at the Department of Electric Power Engineering in the Power Systems group at the Norwegian University of Science and Technology (NTNU). My supervisor has been Professor Gerard L. Doorman.

The work was done within the KMB project "Balance Management in Multinational Power Markets" by SINTEF Energy Research. The project was financed by the Norwegian Research Council, the Next Generation Infrastructure Foundation in the Netherlands, the Norwegian and Dutch TSOs as well as several further project partners.

Acknowledgements

First and foremost I want to thank my supervisor Prof. Gerard L. Doorman from NTNU for providing me with the opportunity of my doctoral studies and guiding me through them. He has always shown great interest in my work and been available for discussions or in the need of help. I highly acknowledge his constructive criticism and encouragement.

I further owe a debt of gratitude to the Balance Management project and especially its manager Dr. Ove S. Grande from SINTEF Energy Research. A special thanks goes to the cooperating PhD students Alireza Abassy and Reinier van der Veen at Delft University of Technology for fruitful discussions and the sharing of knowledge. I also acknowledge all the project partners for their insight and comments received during several project meetings and workshops.

I want to thank my colleagues and friends at NTNU and SINTEF Energy Research for the pleasant working environment. I will remember all these nice social gatherings we had. A special thanks goes to Hossein Farahmand, who accompanied me as fellow PhD student in the research project, for all the time spend together, in order to discuss and compare our work. Furthermore, a thanks goes to Dr. Steve Völler for all his valuable comments. Finally, Tobias Aigner receives my special gratitude for sharing knowledge, data, publications, weekends in the office, several beers and for welcoming me each day nice and warmly.

Last but not least I want to thank for the encouragement and patience of my family and friends, quite a lot of whom accepted that we would not see much of each other during this time. A special thanks goes to Susan for paving the way to these studies. Further, a special thanks to Ida for welcoming me here in Norway and introducing me in the society. Finally, I want to express my gratitude to Jorun for her love, kindness, support and patience; for showing me how to finish a PhD and accompanying me there.

To stick with Jimmy Cliff:

"I can see clearly now, the rain is gone
I can see all obstacles in my way
Gone are the dark clouds that had me blind
It’s gonna be a bright, bright
Sun-shiny day."

Summary

In order to ensure a stable operation of the power system, Transmission System Operators have to balance production and consumption of electiricty continuously. For this purpose balancing services are utilised. With the European objective to migrate to a sustainable power production, a significant share of generation is expected to be from renewable sources, with its inherent production forecast errors. To balance this variable production, the requirement for balancing services increases. The Nordic, particularly the Norwegian hydro-based power system is predestinated of providing such balancing services to the continental European power system.

This thesis studies the integration of national regulating power markets, enabling the cross-border exchange of balancing services in Northern Europe. The research encompasses the development of a mathematical model for the regulating power market, which is based on a day-ahead spot market model. Furthermore, data models for the Northern European power system are developed. Succeedingly, these models are utilised for a set of case studies.

The first part of the thesis focuses on the model development and implementation of system scenarios. The mathematical model of the regulating power market comprises the procurement as well as activation of regulating reserves and explicitly addresses the exchange of balancing services. This model is used to assess the integration of national regulating power markets.

Two detailed data models are compiled, encompassing 2010's and 2020's state of the Northern European power system. For these scenarios the outcome of the the day-ahead spot market is analysed, which shows significant changes in the future system dispatch. Taking the system dispatch as input to the regulating power market model, its market outcome is investigated. The analysis illustrates significant cost savings for the integration of national regulating power markets.

The second part of the thesis comprises a set of analyses, executed with the developed models. The increase in power production from renewable energy sources, especially wind power production is taken as a basis for the future development of the power system. With the changes in the power production portfolio in Northern Europe, including higher variability and increased production forecast error, the future outcome of the regulating power market is studied. Moreover, the impact of various forecast horizons for wind power production and the definition of different reserve requirement levels are investigated. In general the analyses illustrate the challenges due to increased power production from renewable sources. These result in higher system imbalances and hence costs in the regulating power market. It is shown, that an integration of national regulating power markets in Northern Europe provides a good possibility to counteract this cost increase, while the system security is enhanced.

The main findings of the research are:

- With a significant increase of wind power production in 2020, whilst a share of fossil fuel power plants is decommissioned, average spot market prices for electricity decrease, but become more volatile.
- Moreover, the operating hours and concurrently net revenues of thermal power plants will be reduced down to a level, where the operation especially of mid-merit power plants will not be profitable any longer.
- In 2010, the potential cost savings by means of integrating Northern European regulating power markets amounts to approximately 140 million € per annum. These savings result from the netting of imbalances between countries and the utilisation of cheaper reserve capacity provided from the Nordic area.
- The assumed forecast horizon of wind power production is essential for the estimation of balancing costs. In 2020, these costs become tremendous, when a forecast horizon of 24 hours is assumed, but are much lower using a 3 hour forecast uncertainties. However, the latter forecast horizon requires liquid intra-day markets.
- With the utilisation of a 3 hour forecast horizon for the wind power production, the analysis shows an increase of 230 million € in system balancing costs from 2010 to 2020.
- In 2020, the cost savings resulting from the integration of regulating power markets amount to 170 million € per annum, which can account for about 70% for the increase of system balancing costs up to 2020.
- In addition to the increase of system balancing costs, the system will be at the limits of secure operation in 2020. Among others, this results in an increasing number of hours with rationing.
- With an integration of regulating power markets the system security is enhanced as well, facilitated by the efficient system-wide utilisation of all available regulating reserves.

Contents

Abbreviations

ACE	Area Control Error
ACER	EU Agency for the Cooperation of Energy Regulators
BRP	Balance Responsible Party
BSP	Balance Service Provider
EC	European Commission
EMPS	EFI's Multi-area Power-market Simulator
ENTSO-E	European Network of Transmission System Operators for Electricity
ERGEG	European Regulators Group for Electricity & Gas
ETSO	European Transmission System Operators
FCR	Frequency Containment Reserves
FRR	Frequency Restoration Reserves
HVDC	High Voltage Direct Current
IRiE	Integrated Regulating power market in Europe
NTC	Net Transfer Capacity
RG CE	Regional Group Central Europe
RGN	Regional Group Nordic
RR	Replacement Reserves
PTU	Program Time Unit
TSO	Transmission System Operator
UCTE	Union for Coordination of the Transmission of Electricity
WPP	Wind Power Production
WV	Water Value

Chapter 1

Introduction

This thesis deals with the integration of regulating power markets in Northern Europe. The motivation for the exchange of balancing services between the Nordic countries and northern continental Europe is addressed in Section 1.1. Section 1.2 presents the framework of the research, the *Balance Management Project*, while Section 1.3 highlights the major scientific contribution of the research. An overview of the content of the thesis with its structure and the underlying publications are finally given in Sections 1.4 and 1.5.

1.1 Research motivation

1.1.1 Electricity production from renewable energy sources

In 2007 a set of ambitious climate and energy targets was set by the EU Heads of State and Government, tackling climate changes. These targets are to be met by 2020, commonly known as the "20-20-20" targets. In reaction on these targets, the European Commission proposed the *EU climate and energy package*[1] in the beginning of 2008 containing the legislation to implement those targets. Among other targets, these include 20% of energy consumption covered by renewable energy sources by 2020 in the European Union.

In line with these specific 2020 targets, the further development is envisioned in the *Roadmap 2050* leading the way to a low-carbon economy with a sustainable power production. To achieve this ambitious goal a significant increase of energy production from renewable sources in the European power system is necessary in most of the member states.

[1] http://www.ec.europa.eu/climate/policies/package/

Already today Denmark has a share of 29% of power production from renewable sources [1], with temporary production levels higher than the demand in the country. This imposes severe challenges on the operation of the power system. While Denmark only constitutes a small part of the European power system, potential operational challenges can be solved with external help. By moving to a sustainable power production portfolio in Europe, system operation paradigms have to change. In order to ensure a secure and efficient operation, the view has to be broadened from national to multinational.

Renewable energy sources are various, such as wind, sun, hydro, bio-gas, etc. Beside the traditional utilisation of hydro power production in Northern Europe, the main share of sustainable power production currently is and prospectively is expected to be from wind[2]. A significant share of power production from renewable energy sources implies a power production from intermittent sources, like wind or solar power. Furthermore, as these energy sources cannot be stored, power has to be consumed instantaneously. This results in a varying and not perfectly predictable power production. As production always has to equal the demand for electricity, resources to balance the fluctuating production are required.

1.1.2 System balance management

Consumption and production of electricity in a power system have to be in balance continuously, as electricity cannot be stored in the transmission system to a large extent[3]. Each disturbance of the equilibrium between consumption and production (imbalance) leads to a deviation of the system frequency from its set point. These deviations affect the operation of the power system and connected electrical devices. Large disturbances can cause disconnections, eventually leading to black-outs of parts or the whole power system. Thus, imbalances between production and consumption have to be handled continuously in order to ensure a secure system operation.

Beside imbalances resulting from outages of generation or transmission facilities, these occur due to consumption forecast errors and increasingly due to the power production from renewable energy sources. Consumption as well as the production from renewable energy sources are independent varying processes. Figure 1.1 shows the forecasted and actual values for load and wind power production for the first week in December 2011 in Eastern Germany provided by

[2] The largest share of WPP will be in and along the North Sea. This includes onshore as well as offshore WPP. Optimistic prognoses expect up to 96 GW of WPP in Northern Europe in 2020 [2].

[3] Due to the inertia of the power system, small deviations in the time frame of seconds are handled within the transmission grid.

the according TSO[4]. The figure illustrates, that the general pattern of load and wind power production can be forecasted quite well. However, a certain forecast error remains, resulting in imbalances. To handle these imbalances, balancing services are necessary, which are mostly provided by thermal power plants in this area.

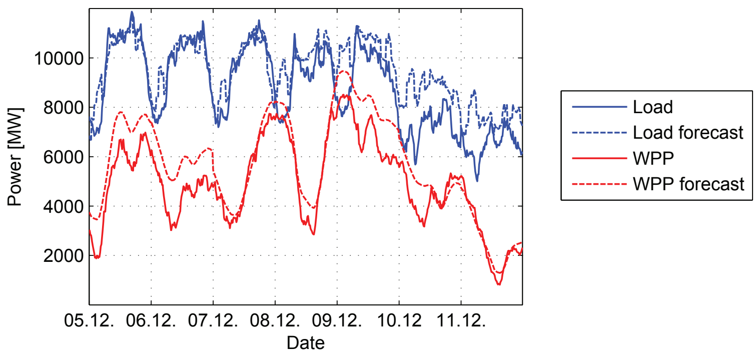


Figure 1.1: Actual and forecasted load and wind power production in December 2011 (50Hertz control area)

One further type of power production from renewable energy sources is hydro power. It has an intermittent energy source (precipitation) as well, but additionally has a large storage capabilities in hydro reservoirs. In the Nordic countries a large share of power production is based on hydro, especially in Norway with almost 100% of production from hydro power. Beside the technical features of hydro turbines, allowing rapid changes in the production level[5], the characteristics of the Nordic hydro system[6] facilitates a higly flexible power production. On the other hand, the interconnection of reservoirs in water courses with certain discharge requirements complicates the planning of the hydro power production. Furthermore, due to the stochastic inflow to the reservoirs and the potential storage with time-horizons longer than a year, the long-term utilisation of the stored water has to be optimised.

Considering the long-term hydro scheduling, the high production flexibility and the large hydro power production capacity, the Nordic power system is

[4]For further data see http://www.50hertz.com

[5]Hydro turbines can change there electricity output with more than 40% of their nominal capacity per minute, which is ten times as fast as thermal turbines, with the exception of open-cycle gas turbines [3].

[6]Especially the Norwegian system contains big reservoirs and hydro power plants with large heads. The hydro reservoirs are able to store the inflow on a long-term.

capable of providing balancing services to continental Europe. These can be used to balance fluctuating power production from renewable energy sources in continental Europe.

1.1.3 Exchange of balancing services

To utilise the Nordic balancing capabilities in continental Europe an exchange of balancing services between two asynchronous systems is necessary. Figure 1.2 shows the northern part of the European interconnected power system together with the corresponding Transmission System Operators. The Nordic synchronous system with its control areas is plotted in green, while the continental system is labelled in orange. The dotted red line indicates the boundary between the two synchronous systems, cutting Denmark in a western and an eastern control area. Within a synchronous system, control areas are connected by AC lines. However, the asynchronous systems are connected with HVDC lines, across which balancing services need to be exchanged.

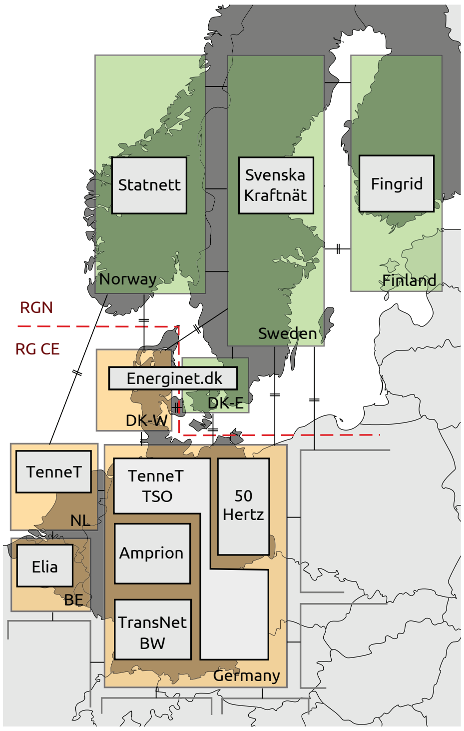


Figure 1.2: North Europe's control blocks [4]

In the European power market environment, balancing services are used to balance power production and consumption. These services are traded in regulating power markets, which are national markets by now.

With its Electricity Market Directive 2009/72/EC the European Union enforces the contemporaneous process of liberalisation and integration of national European power markets. Regulation 714/2009 explicitly addresses cross-border issues. While there is significant progress in the coupling and integration of day-ahead power markets, the integration of European regulating power markets is only at its initial state. For the first time the integration of European regulating power markets was addressed by the European Transmission System Operators in 2007 [5]. Meanwhile bi-lateral projects for the exchange of balancing services are commenced [6]. However, it still is long way to achieve one integrated multinational Northern European regulating power market.

1.2 The Balance Management Project

In order to study the exchange of balancing services between different control areas / countries and the development of multinational regulating power markets, the project *Balance Management in Multinational Power Markets* was initiated by SINTEF Energy Research in 2007[7].

The main objective of the project is *to design the scientific foundation of a framework for efficient, market-based balancing of power systems that can be implemented in multinational ('regional' in the wording of the European commission) power markets.*

The framework should minimize costs and maximize social welfare by coordinating the dispatch of all available system resources. Besides reduction of costs the overall reliability of systems will be increased due to additional reserve resources. In this regard, it is necessary to obtain good estimates of the balancing cost under various assumptions with respect to the integration of balancing markets.

Although the project's objective has a general scope, the focus is on the exchange of balancing services in Northern Europe, including the Nordic countries Denmark, Finland, Norway and Sweden as well as the continental European countries Belgium, Germany and the Netherlands.

[7] http://www.sintef.no/balance-management

1.3 Scientific contributions

As one out of four PhD studies in the project, the research presented in this thesis takes a socio-economic perspective investigating the outcome of integrating Northern European regulating power markets. The scientific contributions are:

- The development of a detailed data model for the unit-commitment and dispatch of the power system in Northern Europe, encompassing the Nordic area, Belgium, Germany and the Netherlands. The model includes a 2010 and a 2020 scenario for the power system. These scenarios are simulated with EMPS, a model developed by SINTEF Energy Research. The resulting day-ahead spot market outcome is investigated.
- The development of a mathematical model for the regulating power market, which is based on the outcome of the day-ahead spot market model. To that end, the procurement and the activation of reserves is modelled explicitly, including the exchange of balancing services across borders. The regulating power market model has the objective of maximising the social welfare in the modelled area. It is used to assess the integration of national regulating power markets.
- A set of case studies analysing:
  - The large scale wind integration in the power system on the system balancing by means simulating the 2020 scenario
  - The impact of wind forecast uncertainty on the regulating power market outcome
  - Different reserve requirement levels and their impact on the system security as well as the regulating power market outcome
  - The outcome of reserving transmission capacity to the exclusive utilisation in the regulating power markets
- Quantifying the socio-economic benefit, that can be achieved by the integration of regulating power markets. The main reasons for the potential savings are pointed out as:
  - Procurement of cheaper reserves in the Nordic area, which are required in continental Europe
  - Reduced reserve activation due to the netting of imbalances

1.4 List of publications

The main research contributions are presented in the following publications. These publications form the foundation of the thesis.

Publication A S. Jaehnert and G. Doorman. "The Northern European power system dispatch in 2010 and 2020 expecting a large share of wind power production." Submitted to the *IEEE Transactions on Power Systems*, 2011. Resubmitted in March 2012 after the first review.

Publication B S. Jaehnert and G. Doorman. "Modelling an integrated Northern European regulating power market based on a common day-ahead market." In *33th IAEE International Conference*, Rio de Janeiro, 2010.

Publication C S. Jaehnert and G. Doorman. "Assessing regulating power market integration in Northern Europe". Accepted for the *International Journal of Electrical Power & Energy Systems*, 2012.

Publication D S. Jaehnert and G. Doorman. "Reservation of transmission capacity for the exchange of regulating resources in Northern Europe: Is there a benefit?" In *11th IAEE European Conference*, Vilnius, 2010.

Publication E S. Jaehnert, T. Aigner, G. Doorman and T. Gjengedal. "Impact of large scale wind integration on power system balancing." In *2011 IEEE PowerTech Conference*, Trondheim, 2011.

Publication F T. Aigner, S. Jaehnert, G. Doorman and T. Gjengedal. "The effect of large scale wind power on system balancing in Northern Europe." Accepted for the *IEEE Transactions on Sustainable Energy*, 2012.

Publication G S. Jaehnert and G. Doorman. "European regulating power market operation: The impact of wind forecasts and reserve requirements." In *9th International conference on the European Energy Market*, Florence, 2012.

The research included following additional publications, which are not part of this thesis.

Publication H S. Jaehnert, H. Farahmand and G. Doorman. "Modelling prices using the volume in the Norwegian regulating power market." In *2009 IEEE PowerTech Conference*, Bucharest, 2009.

Publication I S. Jaehnert et al. "Balance Management in Multinational Power Markets." In *Enerday 2010*, Dresden, 2010.

1.5 Thesis outline

This thesis is prepared on the basis of the previously listed publications. Chapter 4 to 8 include parts of these publications, which is outlined in the beginning of each of these chapters. The motivation for the research and their main contributions were given in the previous sections. The main body of the thesis consists of two parts. The first part describes the modelling of the European power markets, while the second part presents the set of analyses, which were performed. The thesis is structured as follows:

Chapter 2 compiles the background for the research, finalising with a review of relevant literature in the field of the research.

Part I

Chapter 3 introduces the approach for modelling the European power markets. The general overview includes schematics of the simulation process as well as a geographic overview of the modelled area.

Chapter 4 describes the day-ahead spot market model EMPS and the developed power system scenarios for 2010 and 2020 which are developed. The outcome of the simulations with the day-ahead spot market model is presented. The presentation of simulation results is taken from **Publication A**

Chapter 5 presents the full mathematical description of the regulating power market model IRiE, which was developed during the research. The chapter is finalised with a brief case study of regulating power market integration, illustrating the capabilities of the model. The chapter compiles **Publication B** and **Publication C**. The presentation of the case study is taken from the latter publication.

Part II

Chapter 6 is based on **Publication D**, which investigates the reservation of transmission capacity for the exclusive utilisation in the regulating power market, taking into account impacts on the day-ahead market clearing.

Chapter 7 presents an analysis of the impacts from large scale integration of wind power production on the regulating power market outcome. The first stage of the analysis is presented in **Publication E**. An extension and update of the analysis is included in **Publication F**

Chapter 8 investigates the impact of various wind forecast horizons and the definition of different reserve requirement levels on regulating power markets. This analysis is presented in **Publication G**.

Chapter 9 finalises the thesis. It sums up the conclusions of the previous chapters and gives recommendations for further research topics.

Chapter 2

Background

The previous chapter outlined the future challenges to the European power system, in particular the integration of power production from renewable sources. This chapter compiles a background of the European power system, its operation and liberalised European electricity markets.

Section 2.1 presents the organisation and operation of the European power system, including a brief overview on established Northern European power markets.

As electricity is a special commodity, which cannot be stored in large amounts, its production and consumption need to be in balance continuously. In order to keep the system in balance different control mechanisms are necessary. These control mechanisms and their trade in the form of balancing services is addressed in Section 2.2.

The contemporaneous process of integrating European power markets, focusing on the integration of regulating power markets, is reviewed in Section 2.3.

Finally, Section 2.4 constitutes a literature review, including a comprehension of surveys and analyses, which address national regulating power markets and their integration.

2.1 Power system organization and operation

Since the beginning of the 1990s restructuring of the electricity sector has taken place in Europe. Historically, vertically integrated utility companies or governmental institutions owned and operated production, transmission and distribution facilities, with end-consumers as their costumers.

The aim of deregulation and liberalisation in the electricity sector is to form competitive electricity markets, facilitating an efficient production and retailing of electricity. A competitive European electricity market should provide incentives for the investment in new power production including production from renewable energy sources (RES), achieving the ambitious goal of 20% electricty production from RES. According to the European Commission [7], a competitive internal European electricity market should promote a more efficient use of energy, for which the secure supply of energy is preconditional.

Along with the deregulation process comes a necessary unbundling of the vertical integrated industry, leading to separated generation, transmission and distribution companies. Unbundling and hence the increased competition will lead to an efficient utilisation of resources and will give the right incentives to invest in the generation and transmission system [7].

The deregulation started in England and Wales with its Electricity Act in 1989 followed by Norway with its Energy Act in 1990. In 1996 the European Union introduced the Electricity Market Directive 1996/92/EC enforcing the liberalisation process. The Directive states that, the *"(...) establishment of the internal market in electricity is particularly important in order to increase efficiency in the production, transmission and distribution of this product, while reinforcing security of supply and the competitiveness of the European economy and respecting environmental protection."* [8, pg. 1].

2.1.1 The European power system

Today the European power system consists of five interconnected synchronous subsystems, all working at a nominal frequency of 50Hz (see Fig. 2.1). The separate synchronous systems are mutually interconnected by high voltage direct current (HVDC) lines. The power systems cover 34 European countries, continuously serving over 530 million customers with electricity at an annual consumption of about 3200 TWh (in 2011) [9].

With the foundation of the European Network of Transmission System Operators for Electricity (ENTSO-E)[1] as the successor of ETSO[2], the various European power systems are now coordinated under one body. Thus, technical operation rules in the individual power systems are expected to converge gradually. Each of the synchronous subsystem is represented by one regional group in ENTSO-E. Table 2.1 lists the regional groups and their according former organisation names.

In addition to the system-based regional groups, voluntary regional groups are introduced addressing special tasks. Among them, the Voluntary Regional

[1] http://www.entsoe.eu

[2] The organisation of *European Transmission System Operators* was formed in 1999 by the regional groups of European TSOs in the course of the development of regional European power markets.

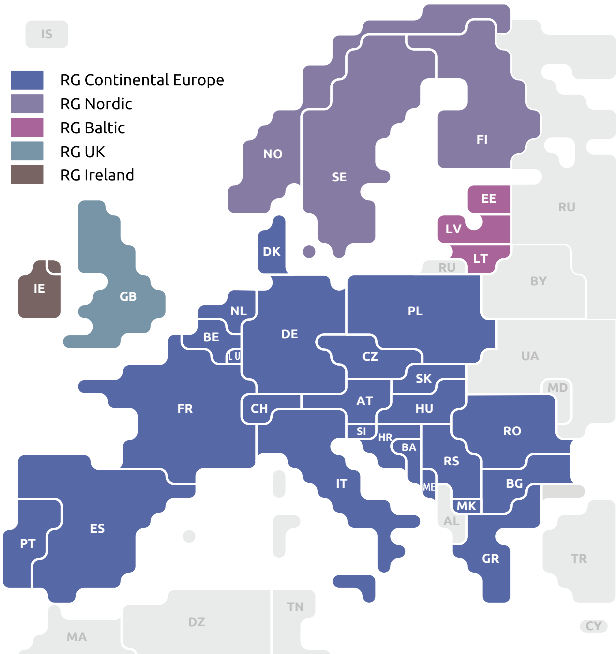


Figure 2.1: Europe's synchronously connected systems [10]

Table 2.1: Synchronous areas / regional groups under ENTSO-E [10]

Abbr.	Name under ENSTO-E	Former name
RG CE	Regional Group Continental Europe	UCTE
RGN	Regional Group Nordic	Nordel
RGB	Regional Group Baltic	BALTSO
GBRG	Regional Group Great Britain	UKTSOA
INI-RG	Regional Group Ireland-Northern Ireland	ATSOI

Group Northern Europe concentrates on the joint operation and security of supply of the Nordic and the northern part of the continental European synchronous systems. The voluntary group especially deals with operational issues related to the HVDC-interconnectors with the focus on system security issues and market operation [10].

2.1.2 The electricity sector

Fig. 2.2 depicts the general structure of the unbundled electricity sector. The structure chart is divided into two main parts. Firstly, the provision of electricity from the generation via transmission to the consumption, which implies the physical flow of electricity. Secondly, it includes the trade of electricity, between these three entities mentioned above, implying a financial flow.

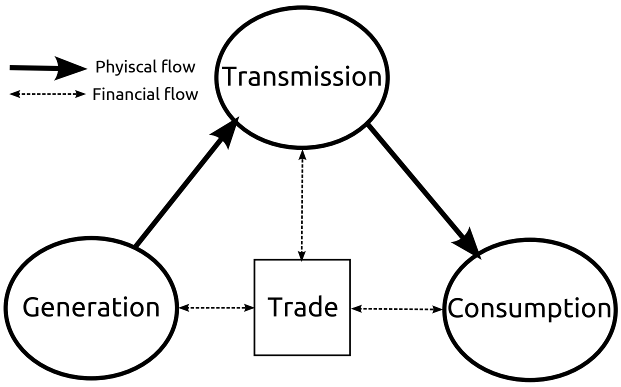


Figure 2.2: Structure of electricity markets

Consumption

The main driver for the development of a power system is the demand for electricity. The consumption of electricity is a stochastic process, which however can be forecasted to a certain extent. The consumption has a quite clear daily, weekly and seasonal pattern, which in certain countries has an additional temperature dependency[3].

[3]The temperature dependency results from a potential high share of installed electrical heating or cooling devices. The former is the case in the Nordic area.

Production

Demand for electricity is supplied by electric power production. Electric power is generated in power plants by converting primary energy sources into electricity. There is a huge variety of energy sources such as fossil sources (e.g. uranium, lignite, hard coal, gas, etc.) and renewable sources (e.g. biomass, wind power, hydro, etc.). The power plants are owned and operated by generation companies, who attempt to profit from their operation.

As electric power production serves a varying demand and electricity cannot be stored easily to a large extent, production has to be adapted to the demand. Most power plants cannot be switched on or off immediately, hence their operation has to be scheduled beforehand. In order to maximise the profit from operating power plants, companies which own several production assets can optimise their production portfolio. This scheduling and optimisation of electric power production is called the unit-commitment and dispatch process.

This process determines, which power plants are set in operation (unit-commitment) and the according production level (dispatch). Performing the unit-commitment and dispatch, several constraints have to be taken into account. Among those, the availability of generation units, marginal production costs, start and stop costs of generation units, ramping rates are of special concern. Beside these general constraints, various challenges occur in the optimisation for different types of power plants.

Thermal power plants: For the generation planning of power plants like nuclear, lignite, hard coal, gas and oil especially ramping constraints as well as minimum up and down times have to be taken into account resulting in a lower flexibility of production.

Hydro power plants: In the case of hydro power production, the marginal production costs are very low, but the available water to produce energy is limited. Thus, the long-term utilisation of the hydro production has to be considered. Furthermore, constraints due to water courses limit the flexibility of hydro production.

Wind power production, Photovoltaics: Production based on the occurrence of wind or sunshine has low marginal cost, but is not available all the time (variable production). Furthermore, the production is not known beforehand, but needs to be forecasted. The variability and the necessity to forecast power production complicates the optimisation process further.

The unit-commitment and dispatch process is normally executed for each hour one day ahead. However, due to an increasing forecast accuracy for the demand and variable power production, schedules can be updated continuously up to the hour of operation. These updates allow production and distribution companies to balance their portfolios, resulting in as few as possible imbalances, cf. Section 2.2.

Transmission

To supply consumers with electricity, which is generated in power plants, a transmission of electricity is necessary. In the last century there has been a development from small independent transmission systems, which connected local generation and consumption, to large interconnected grids, e.g. the European power system. The power system topology is vertically divided in a transmission and a distribution grid, operating at different voltage levels. Furthermore, it is horizontally split into several control areas, with one Transmission System Operator (TSO) and several Distribution System Operators (DSO) in each of the areas. In Europe the electricity grids are mostly owned as well as operated by Transmission System Operators respectively Distribution System Operators.

The system operators have the task to assure a stable operation of the system and to transmit electricity from generators to consumers. To that, the transmission grid serves for the bulk transport of electricity between different regions. The distribution grid, operating at a lower voltage level, provides electricity to end-consumers. System operators are responsible for maintaining the secure and stable operation of the power system, aiming at a high level of security of supply.

Trading

As shown in Fig. 2.2 the physical production, transmission and consumption of electricity is the fundamental part of an electricity market. The overlaying part is the trading between market participants in the power market, resulting in a financial exchange. Trading is done with different products and on different time horizons, from several years ahead up to real-time, shown in Fig. 2.3

Using the disposable trading possibilities, market participants can reduce their financial risk by changing their positions according to their updated expectations. The trading possibilities include bilateral and financial contracts, the day-ahead spot market, intra-day markets, balancing and ancillary services.

Bilateral contracts A big share of electricity is traded via bilateral contracts, also known as over-the-counter (OTC). Two contract parties agree upon an amount of electricity to be supplied in a certain time. Usually these are long-term agreements with a horizon of one up to several years.

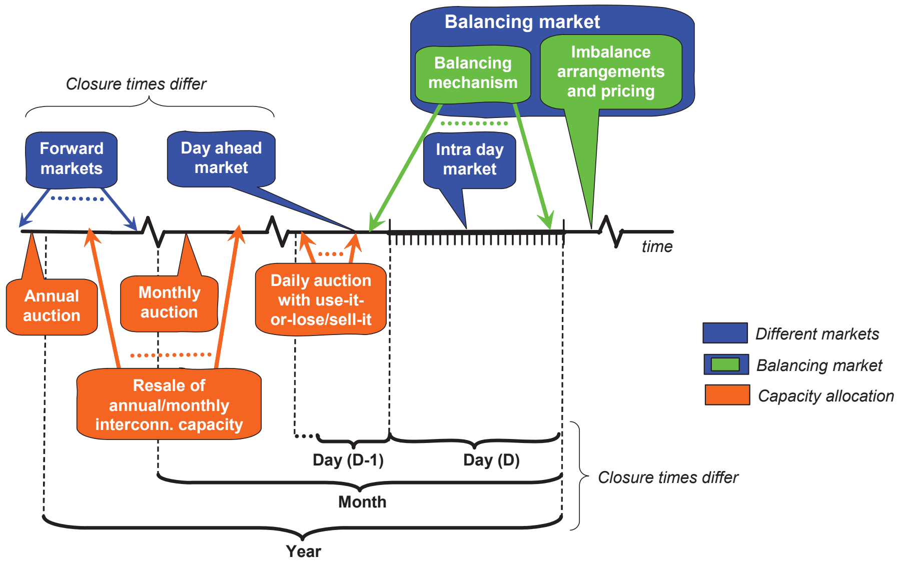


Figure 2.3: Electricity market time line [11]

Financial contracts More standardized long-term contracts are forward contracts, which are traded at power-exchanges, where the amount of electricity and the time of delivery are specified. These contracts do not include the physical delivery of electricity, but are used for hedging based on future price expectations.

Day-ahead spot market As the actual operation gets closer, plans of operation and consumption become more precise and short-term trading is needed. Contrary to the long-term contracts, in the day-ahead spot market the physical delivery of electricity is contracted. In Europe the day-ahead market is mostly a spot market, which is cleared once a day, on the day before the electricity delivery. The day-ahead spot markets are expected to be the place with the highest turn-over of electricity, determining the next day's system dispatch. A main result is the clearing price, the spot market price, which is used as the main price indicator for the commodity electricity.

Intra-day market With real-time approaching and improved forecasts, schedules are updated. In order to account for updated forecasts, trades can be executed in intra-day markets. These are bilateral markets, cleared anonymously at power exchanges. In contrast to the central clearance of the day-ahead spot markets, bids in the intra-day markets are cleared as soon as they match. This rolling clearance of intra-day markets closes shortly before the hour of operation.

Balancing services After the closure of the intra-day markets, the responsibility to match supply and demand of electricity is passed on to the TSOs. In order to ensure this balance TSOs need to acquire balancing services, comprising reserve capacity and balancing energy.

Ancillary services In addition to balancing services, TSOs need further ancillary services to ensure a secure and stable operation of the system. Among others, these include the provision of reactive power for the voltage stability and resources for the black start capability in order to be able to restore the system after a black-out.

2.2 Balancing the system

Electricity is a special commodity, which cannot be stored to a large extent[4]. Thus, the generation of electricity has to match its consumption continuously. Any difference between generation and consumption results in a deviation of the system frequency from the nominal frequency. Maintaining the nominal system frequency is crucial to ensure the stable operation of the power system. As soon as there is a severe deviation of the system frequency from its nominal value, the operation of the system is challenged, potentially resulting in partial or complete black-outs of the power system, see also [13].

To ensure a safe and stable operation of the power system, there are legal rules of operation for each of the synchronous systems. In Northern Europe, these operation rules are laid down in the UCTE Operation Handbook [14] (valid in the continental power system - RG CE) and in Nordel's system operation agreement [15] (valid in the Nordic power system - RGN). These operation rules define a set of control mechanisms respectively ancillary and balancing services. The various control mechanisms and balancing services are presented in the following. Section 2.2.1 elaborates on the technical characteristics of the control mechanisms, whereas succeeding Section 2.2.2 reviews the trade of the according balancing services in a regulating power market.

2.2.1 Control mechanisms

In Europe TSOs are the entities obliged to operate the transmission system. Thus, they are responsible for keeping the system balanced. The Northern European countries with their according TSOs are shown in Fig. 1.2. In the figure, the red dotted line indicates the border between the Nordic (RGN) and the continental European (RG CE) synchronous systems. There are AC-interconnections between the countries within a synchronous system and HVDC lines connecting both synchronous systems.

For the system operation TSOs have several control mechanisms at their disposal. Among those mechanism is a set of frequency control mechanisms, which are used to keep the system in balance. Due to diverse characteristics of the synchronous systems, these control mechanisms differ in RGN and RG CE. There are two approaches to classify the control mechanisms. The first approach, introduced by ETSO [5], does the classification by the objective of utilising the mechanisms. The division is done in the following way:

[4]Due to its inertia a small amount of electricity is stored in the power system. Thus, small deviations are handled within the transmission grid. However, the time-frame of storage is not more than a couple of seconds, cf. [12].

Frequency containment reserves (FCR) *"... are operating reserves necessary for constant containment of frequency deviations (fluctuations) from nominal value in order to constantly maintain the power balance in the whole synchronously interconnected system. Activation of these reserves results in a restored power balance at a frequency deviating from nominal value. This category typically includes operating reserves with the activation time up to 30 seconds. Operating reserves of this category are usually activated automatically and locally."* [5, pg. 15]

Frequency restoration reserves (FRR) *"... are operating reserves necessary to restore frequency to the nominal value after sudden system disturbance occurrence and consequently replace FCR if the frequency deviation lasts longer than 30 seconds. This category includes operating reserves with an activation time typically between 30 seconds up to 15 minutes. Operating reserves of this category are typically activated centrally and can be activated automatically or manually."* [5, pg. 15]

Replacement reserves (RR) *"... are operating reserves necessary to restore the required level of operating reserves in the categories of frequency containment (FCR) and frequency restoration (FRR) reserves due to their earlier usage. This category includes operating reserves with activation time from several minutes up to hours."* [5, pg. 15]

However, the definition of control mechanisms used in the operation rules of the synchronous systems differs from the first approach. Here, the control mechanisms are classified by their technical and operational implementation.

Regional Group Central Europe

The control structure used in RG CE, according to its operation handbook, is depicted in Fig. 2.4. The control mechanisms are divided by their sequence of activation and are sorted hierarchically. As shown in the schematic, all control mechanisms react on the system frequency, which is the central control signal.

The implemented control structure includes the following mechanisms:

Primary control *"...aims at the operational reliability of the power system of the synchronous area and stabilises the system frequency at a stationary value after a disturbance or incident in the time-frame of seconds, but without restoring the system frequency and the power exchanges to their reference values."* [16, pg. 4]

Secondary control *"...makes use of a centralised and continuous automatic generation control, modifying the active power set points / adjustments of generation sets / controllable load in the time-frame of seconds up to*

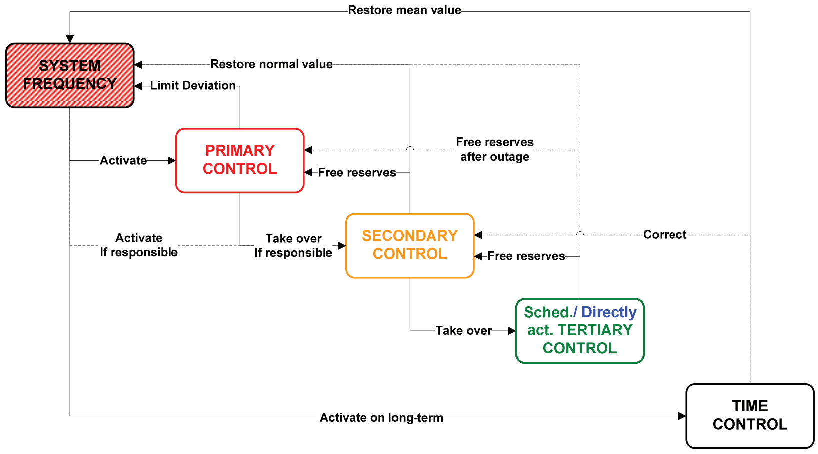


Figure 2.4: Schematic diagram of the control hierarchy in RG CE [16]

typically 15 minutes after an incident. Secondary control is based on Secondary control reserves that are under automatic control." [16, pg. 12]

Tertiary control *"...is primarily used to free up the secondary reserves in a balanced system situation, but it is also activated as a supplement to secondary reserve after larger incidents to restore the system frequency and consequently free the system wide activated primary reserve. Tertiary control is typically operated in the responsibility of the TSO."* [16, pg. 25]

Time control monitors and limits *"..discrepancies observed between synchronous time and universal co-ordinated time (UTC) in the synchronous area."* [16, pg. 29]

Regional Group Nordic

In the Nordic system reserves are basically divided into frequency controlled reserves and fast active reserves. Frequency controlled reserves (FCR) are activated automatically by frequency deviations. Fast reserves are activated manually in order to free automatic activated reserves. In addition there are peaking reserves, which are utilised during peak load situations, to ensure adequate generation capacity. Peaking reserves can take several hours to be activated, thus they do not interfere with real-time control mechanisms.

In RGN the control mechanisms are defined as the following:

Frequency controlled normal reserve (FCNR) *"...is the momentarily available active power available for frequency regulation in the range of 49.9 – 50.1 Hz and which is activated automatically by the system frequency." "In the event of a rapid change of frequency to 49.9/50.1 Hz, the reserve shall be regulated upwards/downwards within 2-3 minutes."* [15, pg. 17]

Frequency controlled disturbance reserve (FCDR) *"...is the momentarily available active power available for frequency regulation in the range of 49.9 – 49.5 Hz and which is activated automatically by the system frequency." "In the event of a frequency drop to 49.5 Hz caused by a momentary loss of production (...) frequency controlled disturbance reserve shall be regulated upwards within 30 seconds."* [15, pg. 17]

Automatic reserves (AR) are planned to be introduced in the Nordic power system [17, pg. 19]. E-Bridge Consulting GmbH [18] discusses its requirements, recommending the implementation of a Load Frequency Control (LFC).

Fast active disturbance reserve (FADR) *"...is the manual reserve available within 15 minutes in the event of the loss of an individual principal component (production unit, line, transformer, bus bar etc.)."* It *"...shall exist in order to restore the frequency controlled normal operation reserve and the frequency controlled disturbance reserve when these reserves have been used or lost, and in order to restore transmissions within applicable limits following disturbances."* [15, pg. 17]

During the last decade, an increasing amount of significant frequency deviations was observed in the Nordic area. Hence, the introduction of AGC is discussed and planned in RGN [17]. A successful trial AGC operation on selected hydro power plants in Southern Norway was achieved, paving the way for a further joint operation of RGN and RG CE. The introduction of automatic reserves coevally harmonises the operation of the Nordic and continental European system as well as enables the provision of secondary reserves from RGN to RG CE.

A comprehension of the different types of reserves and control mechanisms in RG CE and RGN is given in Tab. 2.2. The overview refers to the previous classifications, showing a certain overlap of the categories FRR and RR. FCR and primary control is similar in all systems, mainly due to its decentral and direct installation on generation units as well as its rather technical nature[5].

[5] Primary control is achieved through the implementation of turbine govenors. It constitutes a P-control loop, with the system frequency as input and the generation of the turbine as output, see also [12].

Table 2.2: Reserve categories and cross references [5]

Category.	Function	Reserves
FCR	contain frequency deviations	primary reserves, FCR
FRR	restore nominal frequency	secondary reserves LFC, AR, FADR tertiary reserves
RR	replace used FCR and FRR	tertiary reserves, FADR

Area control error

A further difference between RGN and RG CE is the calculation and utilisation of the area control error (ACE). Primary control is activated decentrally in the whole system, when a system frequency deviation occurs. As the steady-state frequency is equal in a synchronously interconnected system, there is a solidarity in the activation and utilisation of primary control all over the system. In contrast, FRR is activated centrally by TSOs, likewise based on the frequency deviation. In order to take into account the location of imbalances and activate FRR in the according control area the ACE is calculated. The utilisation of ACE results in a restoration of the prior scheduled exchange between the single control areas. ACE is used in RG CE, but abolished in RGN.

Cross-border control mechanisms

As described above, the control mechanisms in a synchronous power system act system-wide, due to the common system frequency and are only limited to certain country borders by the utilisation of ACE. AC-transmission lines do not need to be controlled actively in order to apply control mechanisms across borders, as it is the case in RGN.

This is different in the case of two distinct synchronous power systems, which are connect by HVDC-lines. As there is no common system frequency, the real-time transmission of HVDC-lines has to be controlled actively in order achieve a cross-border control, cf. [19]. Hence, HVDC-lines form a natural border of control areas and need to be handled particularly, in order to form larger control areas encompassing HVDC-lines.

2.2.2 Regulating power market

After the unbundling of generation and transmission, TSOs do not own resources for balancing services themselves, but need to obtain them by trade. In the framework of the liberalisation of electricity markets these services are traded, either bilateral or via centralised markets, called regulating power markets.

Due to the historic national responsibility for system balancing, market designs and hence terminology differ significantly between the European countries, cf. van der Veen et al. [20] and Vandezande [21]. While *balancing market* is a term commonly used in recent literature, the term *regulating power market* is used throughout this thesis, following the terminology used in the Nordic countries and referring to the naming *Regulerkraft* (Norwegian) and *Regelleistung* (German) used in the according markets.

A general schematic for regulating power markets is shown in Fig. 2.5.

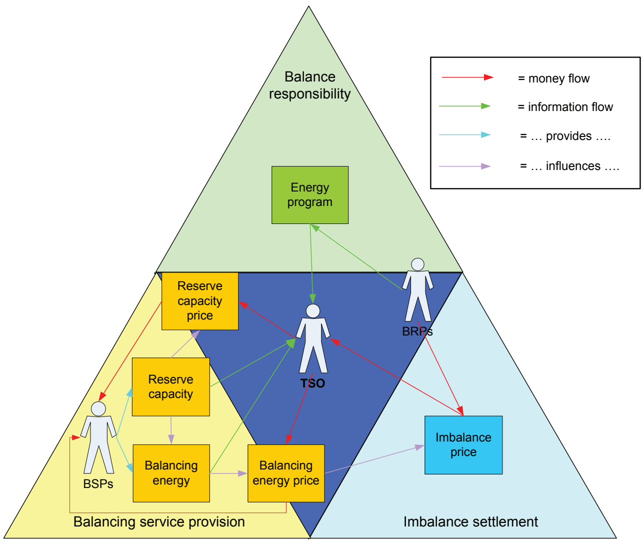


Figure 2.5: Regulating Power Market Structure [20]

There are three main participants in regulating power markets, TSOs, Balancing Service Providers (BSP) and Balance Responsible Parties (BRP). TSOs are the entities responsible to balance the power system, hence running the regulating power market. In order to balance the system, TSO obtain balancing services from BSPs. Outside a certain time-frame, called Program Time Unit (PTU), TSOs pass on their balancing responsibility to BRPs. The BRPs need to have a balanced portfolio over each PTU, according to their schedule submitted to the TSO ex-ante. Ex-post imbalances of BRPs over each PTU are settled with the TSO. The length of one PTU is 15 minutes in RG CE and one hour in RGN. The introduction of a PTU length of likewise 15 minutes is currently discussed in RGN.

2.2.3 Balancing services

The balancing services encompass all the control mechanisms described in Section 2.2.1. In contrary to the day-ahead spot markets, where solely energy delivery is traded, in regulating power markets the capacity (MW) and energy (MWh) are distinguished. To that end, balancing services encompass products of these two different types, namely **reserve capacity** and **balancing energy**.

Reserve capacity refers to the procurement of regulating reserves, where BSPs are paid by TSOs for the availability of regulating reserves, which can be activated in real-time. Payments for reserve capacity are done in €/MW for the whole procurement horizon. In contrast, balancing energy refers to the actual activation of regulating reserves by TSOs in real-time. The delivery of balancing energy from BSPs to TSOs is paid in €/MWh.

There are significant differences in the frequency of market clearance and remuneration for balancing services among the European countries. Not all of the balancing services necessarily need to be traded in all of the countries. Furthermore, bids for reserve capacity and balancing energy might not be independent, as it is currently the case in Germany.

Tab. 2.3 and 2.4 give an overview for the balancing service remuneration in the Northern European countries, for RG CE and RGN respectively. In addition to the different definitions of control mechanisms, these tables clearly show the lack of harmonisation between the different national regulating power markets in Northern Europe.

Table 2.3: Balancing services remuneration in RG CE [22, 23, 24, 25, 26, 27]

		DE	NL	BE	DK-W
Primary	capacity	weekly	mandatory	4-yearly	daily
		pay-as-bid	-	bilateral	marginal
	energy	unpaid	unpaid	unpaid	unpaid
		-	-	-	-
Secondary	capacity	weekly	annually	2-yearly	monthly
		pay-as-bid	bilateral	pay-as-bid	pay-as-bid
	energy	weekly	daily	daily	daily
		average	marginal	pay-as-bid	spot-based
Tertiary	capacity	daily	unpaid	4-yearly	daily
		pay-as-bid	-	bilateral	marginal
	energy	daily	daily	daily	daily
		average	marginal	mixed	marginal

Table 2.4: Balancing services remuneration in RGN [26, 27, 28, 29, 30]

		NO	SE	FI	DK-E
FCR	capacity	yearly / daily marginal	weekly / hourly pay-as-bid	yearly / daily pay-as-bid	daily pay-as-bid
	energy	unpaid -	unpaid -	unpaid -	unpaid -
AR	capacity	to be			
	energy	decided			
FADR	capacity	yearly / weekly marginal	yearly bilateral	yearly pay-as-bid	daily pay-as-bid
	energy	hourly marginal			

In a market environment TSOs are natural monopolists, cf. [31], being the single entity which owns and operates the transmission grid. Thus, TSOs need to be regulated, which is normally done by governmental institutions. Due to the natural monopoly of TSOs, regulating power markets are single-buyer markets. Costs an benefits to TSOs in the regulating power market are mostly recovered by the imbalance settlement and/or assigned transmission tariffs, cf. [27].

2.2.4 Market sequence

Beside the forward, day-ahead spot and intra-day market trading, Fig. 2.3 shows the trading in the regulating power market, which includes the capacity allocation (reserve procurement) and the balancing market (system balancing).

Reserve procurement

The procurement of reserves is done on very different time scales (see Tab. 2.3 and 2.4), from long before the actual operation of the system (e.g. Belgium) to a daily procurement (e.g. Germany).

During the reserve procurement BSPs are contracted to provide reserve capacity to TSOs, according to reserve requirements specified for each control area. The procurement is done for all types of reserves (FCR, FRR and RR). If reserve capacity is procured from a BSP, the BSP is required to give bids for balancing energy. By this means, TSOs ensure that sufficient bids for balancing energy are available, i.e. sufficient regulating reserves are available in the system.

The reserve procurement is not as important in a hydro as in a thermal based power system. Thermal power plants have longer start up times and are most efficient at maximum production. Hence, once they are started up, it is most profitable to operate thermal power plants at full production. Thus, it is necessary to pay those plants to provide reserves, i.e. to start up and operate below maximum production. On the contrary, hydro power plants can be started up quite fast and have their optimal operation point below maximum production. Thus, it is not costly for them to provide regulating reserves. However, during severe situations it might be also necessary to procure reserves in the hydro system .

Considering the Northern European power systems, in RG CE (a thermal based system) it is necessary to procure reserves and pay for their availability. In RGN (with a large share of hydro power production) often reserve capacity is freely available and not necessary to be procured. However, during high-load periods it is also necessary to procure reserves in the Nordic area[6].

System balancing

During the real-time operation of the power system imbalances occur. In the case of such imbalances, reserve capacity (provided by BSPs) is activated. This activation stands for an upward or downward regulation of the system. Based on the frequency deviation, FCR is activated decentrally on all participating power plants primarily. The activation of primary control is expected to be symmetric, i.e. the net balancing energy delivered by FCR is zero. Thus, their activation is mostly not reimbursed.

In the case of larger and longer imbalances FRR is activated centrally. The activation is either done automatically, based on automatic generation control (AGC), or done manually by TSOs. To free up used reserve capacity, RR are activated manually by TSOs. The balancing energy delivered by FRR and RR is reimbursed. The remuneration of these balancing energy is done based on different pricing mechanisms, which are normally defined by the responsible national regulator.

Imbalance settlement

Finally, the imbalances which occurred during real-time operation in the system are settled. The settlement is done between TSOs and BRPs over each PTU. Thereto, the difference between the energy schedule delivered from a BRP to the TSO prior to real-time operation and the actual measured energy flow is determined and integrated over each single PTU. The resulting position of a BRP

[6] In Norway the capacity market RKOM is run only during winter and early spring

can be short or long[7]. As for balancing services, there are different frequencies and pricing schemes for the imbalance settlement in the different countries. Pricing schemes can be as different as one-price or two-price settlement, single or dual-price, average or marginal pricing[8].

[7]A short position means that a BRP delivered less or consumed more energy than scheduled. A long position stands for the opposite direction.

[8]Further details of the imbalances settlement are outside the scope of this thesis. A throughout presentation of various settlement schemes can be found in van der Veen et al. [20] or Vandezande [21].

2.3 European power market integration

In the beginning of the 1990s restructuring and deregulation of European electricity markets was driven by economic policy in order to remove or make cross-subsidies transparent, to allocate capital efficiently and to achieve the lowest cost to end-users. The pioneer was England and Wales with the Act of 1989 [32]. Norway followed with the energy Act of 1990 [33] and the other Scandinavian countries joined the Norwegian market during the 1990s. Spain (1998) and the Netherlands (1999) also created fully competitive markets. Most other European countries followed. Nowadays there are well established power exchanges all over Europe.

The Council of The European Union issued an Internal Electricity Market Directive in 1996 (1996/92/EC) that set goals for a gradual opening of the electricity markets for all member states. The directive was updated in 2003 (2003/54/EC) and 2009 (2009/72/EC), which included the regulations 1228/2003 and 714/2009. Regulation 1228/2003 for the first time explicitly addressed cross-border issues, aiming *"(...) at setting fair rules for cross-border exchanges in electricity, thus enhancing competition within the internal electricity market, taking into account the specificities of national and regional markets."* [34, pg. 3]

2.3.1 Day-ahead spot market coupling

The development of an internal (one single) electricity market in Europe is a long-term process, starting with the integration of day-ahead spot markets. The first steps toward this aim is the establishment of regional[9] markets. Meanwhile there are several regional markets established in Europe, leading the future way [35].

The oldest and best-known regional market is the Nordic market (NordPool). NordPool started as the Norwegian power exchange in 1995, which by now includes forward, day-ahead spot and intra-day trading. The market area was extended to Sweden in 1996, Finland in 1998, Denmark in 2000, partly to Germany in 2005 and Estonia in 2010 [36]. The day-ahead spot markets covers 74% of the consumption in the Nordic countries. Countries are represented by one or more bidding areas in order to achieve a optimal clearing of orders bidden from the different countries.

Central Western Europe (CWE) is another regional market, which is based on market coupling. It started out as the Trilateral Market Coupling (TLC) consisting of France, Belgium and the Netherlands, launched in 2006. In November

[9] 'Regional' is according to the wording of the European Commission. It describes multinational power markets, within a certain region of Europe, e.g. Central Western Europe.

2010 the CWE replaced TLC, now also including Germany, Luxembourg and Austria. These countries already had established power exchanges, which are now coordinated instead of implementing one single trading system. A further step in expanding the market area is the establishment of the Interim Tight Volume Coupling (ITVC)[10], first started between Denmark and Germany and now coupling CWE and NordPool. CWE-ITVC now represents a regional day-ahead spot market area reaching from the Northern Cape to the Mediterranean Sea.

The Iberian regional market called MIBEL was launched in 2007. In contrast to CWE, the existing exchanges in Spain and Portugal divided responsibilities. The Spanish exchange OMEL takes care of the day-ahead market for both countries and the Portuguese exchange OMIP organizes the futures market.

A set of Western European power exchanges has started a project called Price Coupling of Regions (PCR)[11], aiming for a pan-European price coupling. The initiative shall be the basis for an effective European power market, keeping all the current established power exchanges. This development can finally lead to one internal European electricity market.

2.3.2 Integration of regulating power markets

The successful integration of European day-ahead markets, can provide experience and the basis for the integration of European regulating power markets. In contrary to day-ahead markets, regulating power markets still differ quite much due to individual national rules, illustrated by Rebours [37]. For the exchange of balancing services between countries, an integration of national regulating power markets is necessary. This requires a harmonisation of regulating power market rules, as discussed by van der Veen et al. [20]. Furthermore, in January 2007, the European Commission published its energy sector inquiry [38], which stressed the fact that regulating power are highly concentrated, pointing to the fact that the inadequate integration of balancing markets is a key impediment to the development of a single European electricity market.

By now there are several proposals for the cross-border exchange of balancing services, e.g. from ETSO [5], ERGEG [11], Frontier Economics and Consentec [39], Eurelectric [40] and Bundesnetzagentur [41]. These proposals can be generally divided into two approaches, requiring different levels of balancing market harmonization. These approaches sorted by increasing degree of integration are:

[10] ITVC is a volume market coupling solution developed by EMCC and introduced between the Central Western European and Nordic area in 2010, cf. http://www.marketcoupling.com.

[11] http://www.europex.org

TSO-BSP, where TSOs allow BSPs to bid either in the local or a neighbouring regulating power market. BSPs are directly contracted by neighbouring TSOs. This model can only be implemented for the exchange of balancing services in one direction.

TSO-TSO, where BSPs are only contacted to their own TSOs, but TSOs mutually exchange balancing services. The model can be implemented without or with a common merit-order list.

In September 2009 ERGEG, which merged into the EU Agency for the Cooperation of Energy Regulators (ACER)[12] in March 2011, published its "Revised Guidelines of Good Practice for Electricity Balancing Markets Integration (GGP-EBMI)". The Guidelines explicitly state, that *"balancing market integration has been highlighted as a necessary step to reach the ERGEG and EU aim of the development of an effective, competitive single market for electricity across the whole of the EU. Balancing market integration will allow TSOs to more efficiently procure balancing services and avoid inefficient concomitant up and down regulation in adjacent areas. This integration will promote efficient and competitive price formation and market liquidity."* [11, pg. 12]

Furthermore, the Guidelines declare the TSO-TSO model with a common merit-order list as the target model, which however requires the highest degree of harmonisation. To ensure a faster market integration, the TSO-TSO model without a common merit-order list can be accepted and *"(...) a first step towards integrating balancing markets and even the TSO-Provider approach may be implemented in case of incompatible characteristics of balancing markets to ensure a fast implementation"* [11, pg. 25].

There are already a couple of ongoing initiatives to exchange manually activated reserves in Europe, where a pragmatic approach is taken. The grid control cooperation implemented by the four TSOs in Germany additionally includes the imbalance netting as well as the exchange of automatically activated secondary reserves. In the following a brief overview of the initiatives and their implementation is given.

Germany

Due to obligations by the German regulator[13] [42], two different concepts for the integration of the German control areas were suggested in 2008 [43] by the corresponding TSOs. The first concept is a central grid control, i.e. the abolishment of the individual control areas. The second concept is the so called Grid Control Cooperation (GCC), which keeps the current control areas, but

[12] http://acer.europa.eu
[13] Bundesnetzagentur / Federal Net Agency

implements a cooperation between the TSOs. The cooperation encompasses four steps, reaching from an imbalance netting in the first step to a common market with a merit-order list in the last step. From December 2008 to September 2009, this GCC was implemented stepwise by three of the TSOs. In March 2010 the remaining TSO was ordered by the regulator to take part in the cooperation as well [44]. The cooperation is open for the participation of further control areas, with the first and newest member being Western Denmark. Since October 2011 Western Denmark implemented the first module, i.e. taking part in the imbalance netting [45].

Regional Group Nordic

In the Nordic market area, the exchange of balancing energy is already in use for several years. The common Nordic regulating power market was introduced in 2002 [46]. It is based on a cooperation between TSOs, with a common merit-order list for balancing energy, which is displayed on the Nordic Operational Information System (NOIS) [47]. With the establishment of the common Nordic regulating power market ACE was abolished in the Nordic system, utilising regulating reserves system-wide. Since September 2009 there is a harmonisation of rules for bidding and the imbalance settlement across the Nordic area, cf. [48].

United Kingdom - France

The BALIT mechanism, a cross-border mechanism via a HVDC line between the TSOs National Grid (UK) and RTE (France), is in operation since December 2010. Its objective is to enhance balancing competition, reduce costs and increase operational security. The exchange is based on a TSO-TSO approach. To that, in the case of free transmission capacity on the Cross-Channel HVDC line after the closure of the intra-day market, unused surpluses of balancing energy are put at disposal mutually [49]. A similar mechanism is expected to be introduced on the newly commenced BritNed cable [6].

France - Switzerland/Germany

A TSO-BRP approach of exchanging manually activated reserves is taken on the border between France to Switzerland (since 2003) and the border between France and Germany (since 2005). In this project Swiss and German BSPs are enabled to give bids for balancing energy to the French TSO (RTE), in the case of free cross-border transmission capacity, cf. [6, 50].

France - Switzerland

In contrast to the export of manually activated balancing energy from Switzerland to France, since December 2010 there is the possibility of procuring primary reserves from France to Switzerland. The amount is limited to 25MW out of 77MW, which are required in Switzerland. By meeting additional organisational and technical requirements, the exchange of further regulating power market products will be enabled across the Swiss-French border [51].

Norway - Denmark

With the expected commissioning of the Skagerrak IV cable in 2014 [52] it is planned to reserve in total 110MW for the exchange of balancing services on the HVDC connection [53, pg. 13]. These are ±10MW for primary control and ±100MW for secondary control, which will be delivered from Statnett (Norway) to Energinet.dk (Denmark), based on a TSO-TSO approach.

2.4 Regulating power market analyses and integration studies

The day-ahead spot market is a well covered topic and various analyses with national and multinational scope are reported, e.g. European studies as SUSPLAN[14] or TradeWind[15]. A discussion of different power system models is presented by Foley et al. [54]. Various studies have been done on national regulating power markets as well. However, those mostly deal with the investigation of price behaviour, the forecast of prices and the optimisation of bidding strategies for market participants. Another field of investigation covers surveys on regulating power markets and the underlying system balancing/control mechanisms. These studies aid pointing out significant national differences in regulating power markets and show the harmonisation potential as well as necessities.

In the following an overview on relevant literature is presented, covering surveys on, price forecasting in and integration studies of regulating power markets. This literature review is limited to Europe with a scope on Northern Europe[16].

2.4.1 Surveys

Rebours et al. [55, 56] survey frequency and voltage control ancillary services, comprehending the frequency control for 11 different countries. This survey can serve as a basis for future comparison of frequency ancillary services, which mainly represent balancing services in the European system. In the second part, the survey gives an overview on the market design/rules used in the different countries.

A comprehension of balancing services and voltage control services, particularly for the Nordic area, is presented by Kristiansen [28]. This survey likewise presents the definition of the ancillary services utilised in the Nordic area. Succeedingly the market rules for the Nordic countries are presented, including cost estimates for the different services and a discussion of policies and future trends.

Different alternative multinational balancing market designs for Europe are discussed by van der Veen et al. [20, 57]. The survey discusses eight different designs of multinational balancing markets, suggested by literature. The objective is to compile a complete overview of market designs, which will provide the basis for the decision making in future market design.

[14]http://www.susplan.eu/

[15]http://www.trade-wind.eu/

[16]There is manifold literature on system balancing / real-time markets in other parts of the world. However, due to significant differences in market designs and system operation (cf. Rebours [37]), the focus is set on Northern Europe.

2.4.2 Price forecasting

In vertically integrated utility companies the system balancing was realised internally. With the unbundling and establishment of regulating power markets prices for balancing services were introduced. Statistical analyses of market outcomes give insight to characteristics of regulating power markets. These analyses can be used for further forecasting of prices in regulating power markets.

Skytte [58] investigates the cost of acting in the regulating power market on a longer time-horizon. An econometric analysis of the regulating power market is executed. To that a linear model is developed, which is based on the day-ahead spot market price and takes into account the activated regulating volume. It is shown that there is a *premium of readiness* to be paid. In addition, prices for upward regulating balancing energy are affected more by the volume of activated reserves than the price for downward balancing energy in the Norwegian regulating power market.

For a short-term horizon, Olsson and Söder [59] propose a model based on seasonal auto regressive integration moving average (SARIMA) and Markov processes. Its objective is to create scenarios of prices in the regulating power market, which can be used in planning models. The model is applied to the Nordic power market, recreating typical behaviour of prices.

Fleten and Pettersen [60] present an optimisation problem using a method called generation of moment matching scenarios. Scenarios are created for the day-ahead spot price, the prediction error and for the difference of day-ahead spot and the price of balancing energy. The scenarios are utilised to optimise the bidding-behaviour of a price-taking retailer in the Norwegian power market.

Jaehnert et al. [61] propose a linear model, which is extended by error terms. In addition a SARIMA process is introduced in order to generate price scenarios in the regulating power market. The model is used to estimate balancing energy prices for the area of Southern Norway.

Frunt et al. [62, 63] analyse the deployment of balancing energy in the Netherlands. They include an analysis of the so called *raw price difference*, the difference between day-ahead spot market and the price of balancing energy. The analysis points out the increase of imbalance settlement costs during the years. But the costs for the settlement of long respectively short positions become more symmetrical in the Netherlands.

An analysis of the German regulating power market is presented by Riedel and Weigt [64]. It is concluded that *"the most important requirement for economically efficient reserve markets is the joint operation of the four German control areas."* [64, pg. 21] The general suggestion are shorter bidding periods for reserve markets up to the procurement of regulating reserves through intraday markets. Wieschhaus and Weigt [65] test the interdependency between the German day-ahead spot and the reserve market. It is shown, that the spot market outcome is affected by the design of the reserve markets.

A comparable analysis is done by Just and Weber [66] valuing reserve capacity prices against day-ahead spot prices in Germany. The analysis likewise shows that there is no strong correlation between the reservation price of spinning regulating reserves and the forward as well as day-ahead spot market prices, due to long contracting periods for reserve capacity. In order to achieve a more efficient reserve procurement leading to lower reserve capacity prices, the authors suggest a reduction of the contract duration for reserves.

An application for price scenarios in the regulating power market is presented by Matevosyan and Söder [67]. The objective is to minimise imbalance costs for the trade of wind power, which is applied to a wind turbine. It evinces that adopting the suggested strategy, savings of around 5% are achieved.

Jonsson et al. [68] investigate the impact of large-scale wind power on the electricity market, including the regulating power market. It shows, that wind power production has a significant impact, resulting in much more downward regulation, when there is a high wind power penetration in the system [68, pg. 9]. This is argued to occur due to wind power producers risk management or insufficiencies of forecasting models.

Zugno et al. [69] discuss strategies for trading wind power in deregulated energy markets. The newly introduced optimal quantile strategy relies on probabilistic forecasts of wind power production and point forecasts of prices in the day-ahead spot and regulating power markets. A profit optimisation is achieved due to reducing the exposure to risk, which a wind power producer sees.

Farahmand et al. [70] use price scenarios to likewise optimize wind producers bidding strategies. The analysis includes a comparison of two different imbalance settlement schemes, demonstrating their impact on the optimal strategy. For the one-price settlement it is optimal to bid either zero or maximum production, depending on the expected regulating state of the system. Whereas for the two-price settlement it is optimal to bid rather close to the expected production.

Plazas et al. [71] optimise the bidding strategy for a thermal power producer, which participates in the day-ahead spot and the regulating power market (including reserve capacity and balancing energy). Prices and volumes are modelled as ARIMA processes. It is concluded that the use of a stochastic approach is much better than classical deterministic ones and only when prices are near to its expected values the deterministic approach is advantageous.

2.4.3 Integration studies

Several studies and reports are published on the integration of day-ahead spot markets in Europe. However, literature on the integration of regulating power market in Europe is scarce so far.

Bakken [19] studies the exchange of balancing services via HVDC lines between asynchronous areas, concentrating on technical and control aspects. The "primary control co-operation" is found to be not realistic, due to the significant negative impacts on the exporting power system. However, the exchange of secondary control reserves across HVDC connections appears to be of much higher interest. Furthermore, *"(...) during off-peak hours with price-dependent energy exchange, the alternative of using at least part of the HVDC capacity for secondary, or possibly tertiary, control reserves for the thermal system should be seriously considered."* [19, pg. 130] The introduction of AGC in the Nordic area and the possibility of exchanging automatic activated balancing services is presented by Bakken and Uhlen [72].

Due to the decentral characteristics of primary control, there already is a common (mutually supporting) utilisation of primary reserves in a synchronous area, cf. Kundur [12]. However, when it comes to FRR and RR, ACE is still in use in the continental European system, relying on national control. Particularly, ACE is still in use in the four German control areas. The inefficient utilisation of regulating reserves prior to the implementation of the grid control cooperation in Germany is addressed by two studies.

Haubrich and Consentec [73] investigate reserve requirements in the German control areas, which shows there is a significant over-procurement of reserves. In a second part the integration of the control areas is analysed, which results in a possible further reduction of requirements. The reduction mainly results from the netting of imbalances between the different control areas.

The second study done by Lichtblick [74] addresses the saving possibilities for the integration of the German control areas, regarding the activated balancing energy. It concludes, that in 75% of all PTUs balancing energy could be reduced due to imbalance netting, which amounts up to about 30% of the activated balancing energy. The economic savings are estimated to about 300 million €.

TU Dortmund and E-Bridge Consulting GmbH [43] evaluate the two suggested integration concepts for the German control areas and estimate savings of about 200 million €. In the report, which was prepared for the Bundesnetzagentur, the concept of the central grid controller is favoured, however the immediate implementation of the grid control cooperation is suggested.

Flinkerbusch and Heuterkes [75] examine the cost reduction potential in the German regulating power market, including secondary and tertiary reserves. The analysis is based on market data available for 2008. The simulation of a reference scenario and a scenario with an integrated German regulating power market shows a savings potential of about 160 million €, corresponding to 17% of the costs in the regulating power market. The main reason for the saving is observed to be the reduced activation of regulating reserves due to imbalance netting.

The actual implementation of the grid control cooperation is presented by Zolotarev [76]. The presentation demonstrates the successful implementation of the grid control cooperation with savings of about 300 million € per annum.

Frontier Economics [77] investigate the reservation of transmission capacity for the exchange of balancing services based on a stylised simulation, taking day-ahead and balancing prices from different countries as the basis. *"The results show that across all of the scenarios analysed, there would be an expected benefit (i.e. an option value) to retaining the option to use capacity for the purpose of balancing trade."* [77, pg. 28].

A rough estimation of the economic value of exchanging balancing services between the Nordic system and continental Europe is presented by Abbasy et al. [78]. As basis for the analysis it is assumed that sufficient exchange capacity is available. It is concluded that regulating power market integration reduces the total balancing costs significantly. The effect of imbalance netting and thus reduced reserve activation is shown likewise.

Van der Veen et al. [79] do a qualitative analysis of different cross-border arrangements for the exchange of balancing services. For the analysis seven different arrangements are analysed and evaluated by a set of high level performance criteria. The qualitative analysis shows, that ACE netting already is a beneficial integration step. It is suggested not to implement a BSP-TSO trading arrangement and that a common merit-order list has a positive effect. Furthermore, it is concluded that the outcome on individual markets can be quite different.

Succeedingly, Van der Veen et al. [80, 81] and Abbasy et al. [82] present an agent-based analysis of cross-border arrangements for the exchange of balancing services. The analyses [80, 81] confirm the possible benefit of the cross-border arrangements, showing that a common merit-order list is most beneficial. However, it is also stated that economic risks of being imbalanced change significantly with the implementation of a merit-order list. Especially Nordic BRPs will face a much higher risk due to the regional marginal pricing. The specific BSP-TSO cross-border arrangement is studied in [82], investigating the outcome on individual markets. It is concluded that the question for a possible benefit has to be studied specifically for each case. In case of a cross-border exchange between Norway and the Netherlands, the results show, that prices in Norway are not affected largely, however it can influence prices in the Netherlands significantly. This indicates a different resistance in both countries against the integration of regulating power markets.

Vandezande [21] explicitly discusses the integration of balancing markets in Europe. The integration is investigated by the means of Belgium and the Netherlands. The analysis takes into account constructed merit-order bid curves for each country, recorded imbalance data, as well as available transmission capacity between the countries. Simulations show, that in 2008 the imbalance netting and TSO-TSO exchange of balancing energy with a merit-order list, would have induced cost savings of 37%. At the same time the activation of regulating reserves would have been reduced by 22%. It is pointed out that there normally is sufficient transmission capacity available after the day-ahead spot market clearing to net imbalances and exchange the necessary balancing services. This shows that there actually is sufficient cross border capacity available and that network investments are not necessarily required in order to implement the integration of regulating power markets. In a second step the distortion of imbalance settlement due to the exchange of balancing services is analysed. To that end a set of strategies is analysed. *"Due to current differences between imbalance pricing methods in Belgium and the Netherlands, cross-border settlement strategies induce flows that are sometimes opposite to those occuring under [a optimal balancing service exchange]. [These flows] distort - rather than enhance - the optimal deployment of [balancing] services."* [21, pg. 121] Thus, only with a full harmonisation of market designs prices would reflect costs and the most profitable BRP strategies would simultaneously enhance the social welfare.

Farahmand and Doorman [83, 84] analyse the integration of regulating power markets in Northern Europe. The analysis is based on a DC-power flow model and includes a cross-border procurement of reserves as well as their cross-border activation. The simulations for a fully integrated Northern European regulating power market show moderate savings for the reserve procurement, but considerable savings in the system balancing. It is argued, that these saving are due to the netting of imbalances and the activation of cheaper reserves, which are located in the Nordic power system. The analyses clearly illustrate the possibility and profitability of exchanging balancing services between two asynchronous systems, via HVDC lines.

2.4.4 Review conclusion

There is some literature on multinational regulating power markets and the integration of national markets, mostly focussing on Northern Europe. Most of the literature focuses on market design and qualitative rather than quantitative analyses.

The quantitative analyses presented by Van der Veen et al. [80, 81], Abbasy et al. [82] and Vandezande [21] are based on recorded market data, which is not suited for the assessment of future scenarios. Farahmand and Doorman [83, 84], who use a fundamental modelling approach, lack a detailed model for the Nordic hydro system. However, all of these referred analyses point out benefits by integrating national regulating power markets.

Thus, the objective of the research is to quantify the outcome of regulating power market integration in the entire area of Northern Europe, currently and prospectively. To asses the outcome, a multinational regulating power market model for Northern Europe is developed during the research. The model is based on a common day-ahead spot market, covers several countries and includes future scenarios of the power system. Such a model was not found in the literature. The developed regulating power market model and succeeding analyses are presented in the following chapters.

Part I

Modelling

Chapter 3

Power market modelling

The development of the mathematical model for the regulating power market, which is based on a common day-ahead spot market is put forward in the first part of the thesis. This chapter contains an overview on power market modelling. Section 3.1 presents different power market model types. In the succeeding Section 3.2 the chosen modelling approach is presented, including an overview on the simulation process and stating general assumptions.

The following Chapters 4 and 5 elaborate on the day-ahead spot market model and regulating power market model, respectively. Both chapters are finalised with an analysis performed with each of the models, illustrating their capabilities.

3.1 Power market model characterization

Several different approaches have been developed to investigate and forecast power market outcomes and prices. Meibom et al. [85] classify the approaches by five different categories, being financial, statistical, fundamental and game-theoretic models as well as technical analysis. The attempt is to present a short description of the different approaches and give examples for their implementation, especially considering the modelling of regulating power markets.

3.1.1 Financial

Financial models describe the stochastic price movements, for which different stochastic processes are used. Olsson and Söder [59] present a model for the regulating power market using a stochastic process[1] combined with a Markov chain in order to describe the state as well as the price in the regulating power market. Fleten and Pettersen [60] present a momentum based method, which is used to generate price scenarios for balancing energy.

3.1.2 Statistical

In contrast, statistical or econometric models try to include deterministic regressors. Due to the non-storability of electricity, especially the demand has a high impact on market clearing prices. Skytte [58] does an econometric analysis of the Norwegian regulating power market, using the state of the regulating power market and the volume as regressors. Jaehnert et al. [61] extend this approach by a SARIMA process in order to generate price scenarios of balancing energy for southern Norway.

3.1.3 Fundamental

In contrast to the former models, fundamental modelling takes a bottom-up approach. To analyse power markets, generation as well as transmission and demand are modelled explicitly. The basic assumption of most fundamental models is the efficient operation of power markets, leading to a dispatch with minimal system operation costs, which satisfies the demand[2]. This efficient clearing of the power market results in a electricity price, which equals the marginal generation cost of the marginal generation unit.

In order to represent realistic sized electricity systems, a representation of the transmission system is necessary, as there often are transmission limitations between countries or even within country. Congestions on transmission lines lead to different electricity prices in the areas that are connected by the congested transmission lines. There are different approaches of representing the transmission system. The most common are the corridor-based, Power Transfer Distribution Factor (PTDF)-based and the flow-based approaches. The first approach solely utilises Net Transfer Capacities (NTC) as constraints for transmission on a corridor, while the transmission on the corridors is independent. With the definition of PTDFs, the linear inter-dependency of transmission on different lines is described, which is only valid for a certain state of the power system. The last approach includes the full description of the power-flow either as DC- or AC-power flow, which however complicates the solution significantly.

[1] The process used here is a SARIMA process (Seasonal Auto-Regressive Integrated Moving-Average), which is a well established methods to model loads and market prices.

[2] This assumptions results in the modelling of a perfect market, neglecting potential strategic behaviour of market participants.

For a detailed description of power flow methodologies, see e.g. Grainger and Stevenson [86].

Up to now fundamental models are almost only developed for long-term investment analyses, day-ahead spot markets simulations and to assess their integration. Krause et al. [87] present a multi-energy carrier model based on energy hubs, with a general representation of countries. Nüssler and Lienert [88] developed the power market model DIANA for central Europe, which is divided into several regions. Transmission is solely based on NTCs. Meibom et al. [89] introduce the multi-market model WILMAR including the reservation of required reserve and the intra-day market.

A more detailed representation of the transmission grid is presented by EE2 - TU Dresden [90]. In ELMOD the transmission is modelled flow-based, however it only covers Germany in detail. All of Europe is modelled by European Wind Energy Association [2]. This PSST model is expanded by the simulation of reserve procurement and system balancing by Farahmand and Doorman [83, 84].

3.1.4 Game-theoretic

An enhancement of fundamental models is the consideration of game theory in the market clearing process. This allows the modelling of competition and strategic behaviour in power markets. A comprehension of different approaches and current modelling trends is given by Ventosa et al. [91], however regulating power markets are not considered.

Hobbs and Rijkers [92], Hobbs et al. [93] develop and apply a game-theoretic model, which calculates an oligopolistic equilibrium among competing generation companies. The model includes different transmission pricing methodologies. The model is applied to north west Europe. It shows economic inefficiencies and illustrates the effects of generator conjectures regarding the supply of competing generation companies.

Neuhoff et al. [94] discuss differences between a set of game-theoretic models, showing that results converge in the case of a perfect market assumption. However, in the case of considering the strategic behaviour of market participants, the results from the compared models strongly depend on modelling assumptions. This confirms that results of models assuming perfect market behaviour are quite reliable, but that results of game-theoretic models need to be viewed critically.

Van der Veen et al. [80, 81] and Abbasy et al. [82, 95] present analyses of competition in the regulating power markets. The analyses take an agent-based approach in order to analyse the behaviour of single market participants. They assess different market rules and market coupling approaches. However, due to the level of detail and complexity of the simulations only a limited area and snapshots of the regulating power market can be simulated.

3.2 Implemented modelling approach

In order to develop a model of an integrated Northern European regulating power market, a generic electricity market design is assumed, supposing a harmonisation of the national regulating power markets. The regulating power market is based on the outcome of the day-ahead spot market. It is assumed that there is a common Northern European day-ahead spot market, resembling today's situation of day-ahead spot market coupling (ITVC-CWE market coupling, see Section 2.3). The modelled markets are assumed to be perfect, neglecting strategic behaviour of market participants. As mentioned in Section 2.2.2 there are different designs and sequences of electricity markets. Sequence refers to the temporal order of clearing the markets, e.g. procuring required reserves first and clearing the day-ahead spot market afterwards or vice versa. The market sequence concerns the knowledge of day-ahead spot market clearing prices and dispatch when running the regulating power market, particularly the reserve procurement. In case of procuring reserves prior to the day-ahead spot market clearing, an expected day-ahead market clearing has to be taken into account, resulting in a stochastic optimisation problem.

In the presented model, a deterministic approach is implemented. Thus, a sequence is chosen, where first the day-ahead spot market is cleared and subsequently the regulating power market is run. Running the regulating power market includes the reserve procurement and finally the balancing of the power system. The chosen time basis for the day-ahead spot market clearing is one hour according to the European spot markets NordPool, APX and EEX. As PTU length for the regulating power market, i.e. the reserve procurement and the system balancing, 15 minutes are chosen to match the shorter PTU length of RG CE[3].

Following the suggestions by Bakken [19], the exchange of primary control (FCR) across HVDC-lines is unrealistic. Moreover, the procurement of FCR is mandatory in some of the countries (e.g. the Netherlands). A remuneration is only done for the reserve capacity and not the energy, cf. Tab. 2.3 and 2.4. Thus, fast reacting FCR is neglected in the model and it is focussed on FRR and RR as well as their exchange.

The schematic diagram of the power market model is shown in Fig. 3.1. It consists of the following three subsequent steps: the common day-ahead spot market, the reserve procurement and the system balancing. The common day-ahead spot market is simulated by the utilisation of *EFI's Multi-area Power-market Simulator* (EMPS)[4]. The outputs of EMPS include the optimal day-

[3]The current PTU length in RGN is 60 minutes.

[4]The development of EMPS started at the Norwegian energy research institute EFI, which now is merged into SINTEF Energy Research, cf. http://www.sintef.no/home/SINTEF-Energy-Research/Software/EOPS-and-EMPS/.

ahead system dispatch, taking the unit-commitment into account. Furthermore, EMPS calculates area prices and water values. These results are used as inputs to the subsequent steps, which are simulated using the regulating power market model developed during the research, called ***I**ntegrated **R**egulating power market **i**n **E**urope* (IRiE). In the second step the reserve capacity according to defined reserve requirements is procured, resulting in a redispatch of the production and transmission capacity. The redispatch is input to the final step, in which the real-time system balancing is simulated.

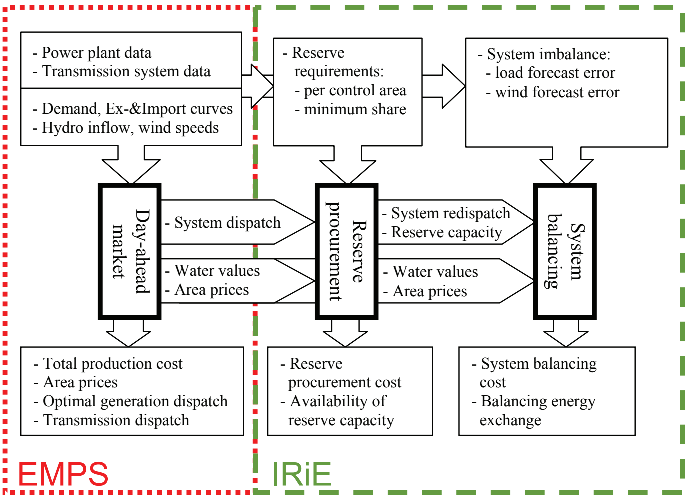


Figure 3.1: Model structure and work flow

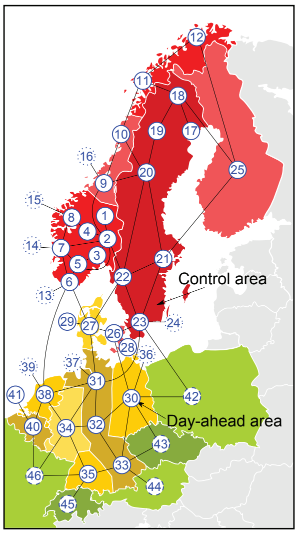
Fig. 3.2 illustrates the geographic spread of the model, consisting of 46 interconnected areas in the 2010 and 2020 scenarios. The areas are defined according to country borders, the geographic distribution of generation capacity and existing bottlenecks in the transmission system.

The model includes a detailed description of the Nordic area (red) and north west Europe (yellow) as well as a generalized description of neighbouring countries (green). Offshore areas with no wind power production installed in 2010 are plotted with dotted lines. The detailed modelled areas (1-41) are aggregated into 12 and 15 control area[5]. These aggregated areas are in accordance with the current control areas in the RG CE [96] and in RGN[6] [15]. In October 2011

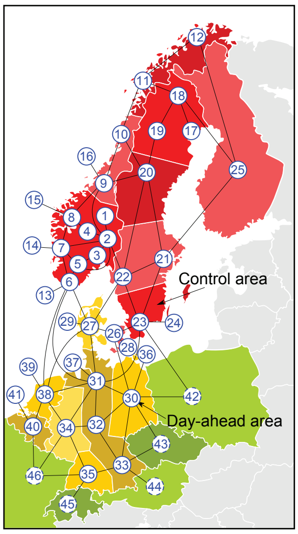
[5]Up to now Finland is disregarded in the regulating power market simulations, due to insufficient system data.

[6]According to RGN's (Nordel's) System Operation Agreement [15] the Nordic area is one control area, with a common Nordic merit order list of bids for balancing energy. Just as

Sweden was split in four areas [97], resulting in an increased number of control areas, which is expected still to be valid in 2020.



(a) 2010



(b) 2020

Figure 3.2: Geographic overview of the day-ahead spot market and regulating power market models

The system is modelled in its 2010 and 2020 state regarding the installed generation capacity, the transmission system, the exchange with neighbouring countries, power production and consumption. The power market model simulates a generic year with 364 days including 8736 hours, which corresponds to 34944 PTUs. To model the stochastic power production from renewable sources, 75 different annual inflow and corresponding wind speed scenarios, covering the years 1931 to 2005, are used during the day-ahead spot market clearing. Afterwards a set of characteristic years is chosen to simulate the regulating power market.

The following chapters 4 and 5 contain a further description of the day-ahead spot market as well as regulating power market model.

the areas defined in the day-ahead market clearing by NordPool [36], the Nordic system can be split into areas during real-time system operation, taking into account congestions. In this case the activation bids can deviate from the common merit-order list. The areas during real-time operation can, but do not need to match the day-ahead areas. The division chosen in this model is according to 2010's division.

Chapter 4

EMPS - The day-ahead spot market model

In this chapter the model and simulations of the common Northern European day-ahead spot market are presented. It includes scenarios for 2010's and 2020's state of the power system in Northern Europe. The day-ahead spot market model is described comprehensively and assumptions for the scenarios are stated. Simulation results for the two power system scenarios are presented and discussed succeedingly.

The chapter includes **Publication A**, which presents an investigation of a possible future development of the Northern European power system, expecting a large increase of installed wind power production capacity. Section 4.2 to 4.5 are identical to Section III to VI of the publication, with minor editorial changes. In addition, this thesis includes Section 4.1, which elaborates the methodology of EMPS in more detail than in the publication. Section 4.2 presents underlying data for the 2010 and 2020 scenarios. Simulation results of both scenarios are presented in Section 4.3 and discussed in Section 4.4. Section 4.5 finalises the chapter with concluding remarks on the simulations made.

4.1 Power market model

The common Northern European day-ahead spot market is simulated with EMPS [98]. It is a mid- and long-term operation scheduling model on a weekly basis with a time horizon of several years, suited for hydro-thermal power systems and taking the unit-commitment into account. Its objective is the socio-economic optimal dispatch for generation, transmission and consumption of electricity, assuming perfect market behaviour.

EMPS is developed by SINTEF Energy Research [99] originally for the Nordic power system, including Finland, Norway and Sweden, explicitly taking into account hydro based power production. As there is no real cost for water, but rather a limited amount of water in the hydro reservoirs, its long-term utilisation[1] has to be optimised. To that end, EMPS contains a detailed water course description for the hydro power production system. Fig. 4.1 shows the sketch of an exemplary water course, including inflow, hydro reservoirs, hydro power plants and the hydraulic interconnections.

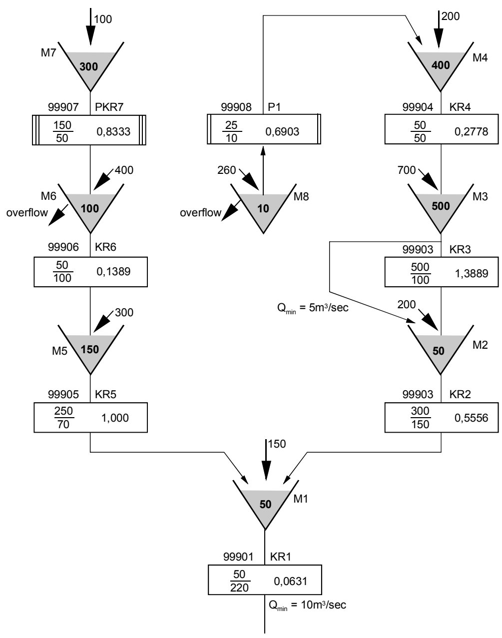


Figure 4.1: Example of a water course defined in EMPS [100]

The EMPS model consists of two parts, the determination of the hydro reservoir strategy and a detailed simulation of the power system.

Within the strategy part the long-term utilisation of reservoirs is determined. Based on stochastic dynamic programming, water values for the water stored in reservoirs are determined, cf. Section 4.1.2. The water value represents the opportunity cost of hydro power production, using the water stored in a hydro reservoir. During the simulation the optimal weekly dispatch of the hydro power

[1] Some of the Norwegian hydro reservoirs store water for several years. Thus, a optimisation horizon of several years is necessary to ensure an optimal utilisation of the stored water.

production, the thermal power production and the transmission is determined through a market clearing process, cf. Section 4.1.3. Weeks are divided in several subsequent periods, by which an hourly resolution of the optimal dispatch is approximated.

4.1.1 System model

The model is divided into several spot market areas, which include aggregated production and consumption. The example of Northern Europe is shown in Fig. 3.2. The areas are connected via transmission corridors, described by their NTCs and linear losses. The area definition is based on country borders, bottlenecks in the transmission system and different water courses.

Each of the areas can contain modules for hydro power, thermal power, wind power and demand, as shown in Fig. 4.2.

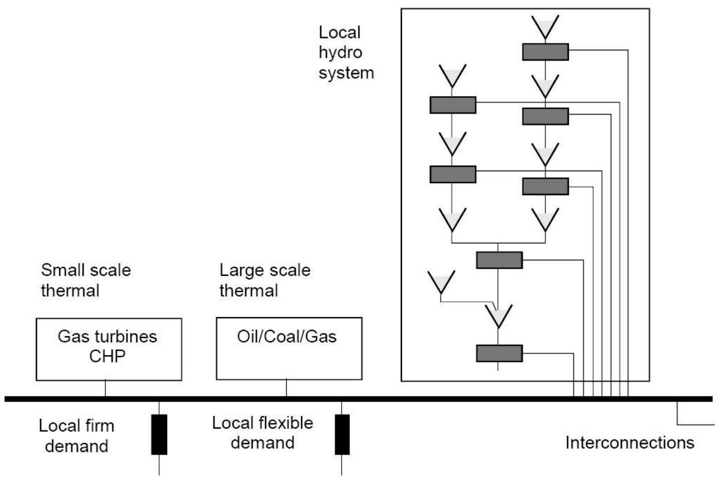


Figure 4.2: Model of an aggregated area with the its utilisable modules [100]

Hydro power production

The hydro power production consists of several modules, each containing storable and non-storable inflow as well as a hydro power station, depicted in Fig. 4.3. In addition to the plant discharge, bypass of the power plant and potential spillage are modelled. These may go to different downstream reservoirs or to the sea.

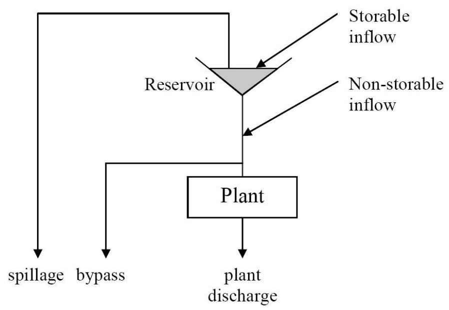


Figure 4.3: Model of an aggregated area with the included modules [100]

Storable inflow goes into the reservoir, whereat non-storable inflow has to be used for power production instantaneously. Inflow is available as weekly recorded data with a high geographical resolution, covering more than 75 years.

Reservoirs are defined by their volume and a piecewise linear curve describing the relation between reservoir filling and the level above sea. The reservoirs are discharged through hydro power plants, which are defined by their energy conversion factor (kWh/m^3). The power plant output is defined as a piecewise linear function, giving the dependency between the discharge and power production.

Beside the discharge through a hydro power plant, the bypass of hydro power plants and spillage are defined. These are necessary due to constraints in the water course, which are maximum and minimum reservoir levels as well as maximum and minimum discharges.

For pumping the efficiency as well as the source and final reservoir are defined in EMPS.

Thermal power production

In EMPS, thermal power production is modelled by its capacity, the marginal production costs, start-/ stop costs and an availability rate. The availability rate accounts for planned and unplanned outages. The start up state of thermal power plants is modelled with a linear approximation, presented by Warland et al. [101].

Wind power production

Wind power production is modelled as fixed energy input to the system per area, based on installed generation capacity and wind speed data. The wind speed data has an hourly resolution, accounting for the variability of the wind power production.

Demand

Demand is divided into firm and elastic demand. In addition, temperature dependency of the demand can be included, to represent the significant share of electric heating, especially Nordic countries. The firm demand is defined by its annual quantity, a weekly profile during the year and a profile within a week.

Elastic demand respectively flexible demand is defined by a weekly profile and a disconnection price. This flexible demand is used to model dual-fuel boilers and power intensive industry, which has the possibility to react on prices.

Transmission

Transmission corridors are modelled by their NTCs and linear losses, not distinguishing between AC and DC. Exchange to continental neighbouring countries is represented by a scheduled energy exchange rather than a price-dependent exchange.

Reserve capacity

A definition of reserve requirements for countries can be included. In EMPS, the requirements only contain upward spinning reserve, which can be provided from hydro power or running thermal power plants.

4.1.2 Strategy part

In the first part of EMPS, the strategy part, water values are determined, using stochastic dynamic programming. For this determination the hydro system in each area is aggregated into one energy reservoir and one equivalent hydro power plant as well as time series for storable and non-storable inflow. In order to achieve a realistic utilisation of the reservoirs, constraints in the water courses have to be incorporated in the storable and non-storable inflow [98].

Inflow scenarios

In total, inflow data for more than 75 years is available. These inflow records are used to represent the stochasticity of inflow to the Nordic hydro system. Fig. 4.4 shows the aggregated inflow to the Norwegian hydro system for 10 succeeding years. The diagram illustrates significant differences in inflow. However, the main characteristics are the same, with high inflow during late spring, summer and early autumn while the inflow is low during the rest of the year. Thus, the year is split in a filling and a depletion season of the hydro reservoirs.

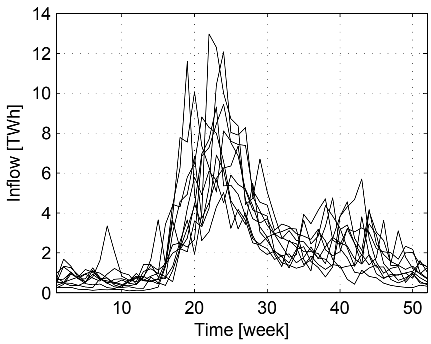


Figure 4.4: Inflow scenarios to the Norwegian hydro system

Water values

To achieve an optimal operation of the hydro power system, the long-term utilisation of water stored in reservoirs has to be optimised. The objective of the optimisation is defined as the expected minimum operation cost $J(x, N)$, from week k until the end of the planning period N. It can be expressed as

$$J\left(x,k\right) = E\left[min\left(\sum_{i=k}^{N} L(P_i, x, i)\right) - S(x, N)\right] \tag{4.1}$$

x represents the reservoir level,

P_i represents the production from a reservoir in week i,

$L(P_i, x, i)$ represents the operation cost in week i, including costs of thermal generation, power purchases, curtailment of demand and possible income from power sales,

$S(x, N)$ is the value of the remaining water in the reservoir at the end of the planning period.

The optimisation is done through backward recursive stochastic dynamic programming, defining the objective as:

$$J\left(x,k\right) = \sum_{i=k}^{N} L\left(P_i, x, i\right) - S\left(x, N\right) = J\left(x, k+1\right) + L\left(P_k, x, k\right) \tag{4.2}$$

The operation cost $L(P_i, x, k)$ is a function of the production from reservoir P_i in each week. Hence, the aim is to find the production[2] which minimizes the operation cost.

$$min_{P_i}\left(J\left(x,k\right)\right) = min_{P_i}\left(J\left(x,k+1\right) + L\left(P_k,x,k\right)\right) \tag{4.3}$$

$$\Rightarrow \frac{dJ}{dP_k} = 0 \tag{4.4}$$

The result of solving the minimisation is the optimal operation strategy for each period k [102], being

$$\frac{\partial L}{\partial P_k} = \frac{\partial J}{\partial x_{k+1}} \tag{4.5}$$

In Equation 4.5

$\frac{\partial L}{\partial P_k}$ is the marginal operation cost in week k

$\frac{\partial J}{\partial x_{k+1}}$ is the dependence of the total future cost on the reservoir level, which represents the marginal water value in week $k+1$ for reservoir level x_{k+1}.

The optimal handling of hydro power production is achieved if the marginal operation cost equals the water value, i.e. the water value is used as the marginal production cost for hydro power. To account for the stochasticity, the calculation is run with all of the inflow scenarios, each with a certain probability. The final water values are the weighted averages of the single inflow scenarios.

The water value calculation is done for each aggregated reservoir in each area. Fig. 4.5 exemplarily shows the water value for one area (Western Norway). It illustrates the dependency water values depend on the week and the reservoir level.

The procedure above describes the calculation of water values for one area. During the water value calculation the areas are disconnected. Thus, the exchange with other areas has to be taken into account exogenously. The exchange is adjusted by running a simulation of the full aggregated model and comparing the difference to the dispatch of the single area. In case of a difference, the exogenously defined parameters describing the exchange are adapted and the water value calculation is rerun. After the dispatch for the single areas and the simulation of the full model has converged, the water value calculation is finished. A detailed explanation of the water value approach is given by Wolfgang et al. [98].

[2] The production from a reservoir per week represents the reservoir utilisation strategy.

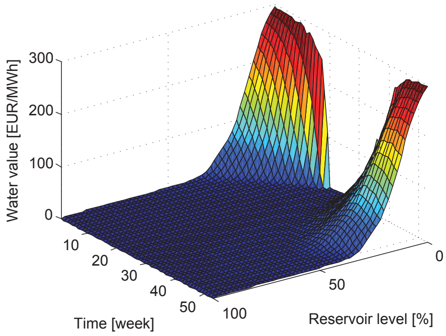


Figure 4.5: Water value map for Western Norway

4.1.3 Simulation part

With the water values calculated in the strategy part, the simulation part is executed. The simulation is run in two stages; first the optimal system dispatch is determined for the full model on the aggregate area level using the calculated water values as the marginal production costs for hydro power plants. Then the dispatch for the detailed reservoir draw-down model is determined, using a rule-based strategy to distribute the optimal production dispatch on the single hydro power plants.

In the draw-down model, reservoirs are divided into two types (buffer and regulation reservoirs), which are run with different strategies. The objective of the reservoir draw-down strategy is to produce a specified amount of energy at minimized operational costs. The minimisation attempts to reduce the risk of spillage during the filling and the avoidance of production capacity shortage during the depletion season.

If the optimal system dispatch cannot be achieved with a detailed draw-down strategy, the optimization of the full model on the aggregated area level is adjusted and rerun. The simulation is run for all the given inflow scenarios. When convergence is reached, the optimal system dispatch is determined, including the power production and transmission for each of the inflow scenarios.

4.2 Model input data

Fig. 3.2 shows the implementation of the Northern European power system in EMPS. Continental neighbouring countries, drawn in dotted circles, are modelled in less detail. Germany is subdivided based on suggestion by Amprion, EnBW TNG, transpower, VE-T [103] and Deutsche Energie-Agentur GmbH

(Dena) [104]. The subdivision of the Norwegian and Swedish systems takes into account known transmission bottlenecks as well as different water courses in the hydro system.

For the Northern European power system a 2010 and a 2020 scenario are developed. Input data and assumptions are stated hereafter. As development plans change continuously, the scenario 2020 does not give the exact year of the system development, but rather a future state of the power system. The adaptation of the power system includes increased WPP capacity, a changed power plant portfolio as well as expanded transmission capabilities.

The 2010 scenario represents the current state of the Nordic and northern continental European power system. NTCs for the transmission corridors are determined according to the methodology proposed by Deutsche Energie-Agentur GmbH (Dena) [104]. Consumption data is taken from the Nordic power exchange NordPool [105], continental TSOs TenneT TSO B.V. [23], Elia System Operator SA [24], 50 Hertz Transmission GmbH [106], Amprion GmbH [107], EnBW Transportnetze AG [108], TenneT TSO GmbH [109] and annual consumption data published by Bundesministerium für Wirtschaft und Technologie [110]. For a detailed overview see Tables 4.7 and 4.8 in the appendix of this chapter. Finally, the 2010 scenario is fitted to reflect the annual generation mix and price characteristics in the modelled countries. The fitting is mainly done by adapting the availability rates of thermal power plants.

The 2020 scenario definition is based on several reviewed reports for the different countries. These are reports by Svenska Kraftnät and Statnett [17], Nordel [111], European Commission [112] for the Nordic system including Denmark, Finland, Norway and Sweden. Reports by Deutsche Energie-Agentur GmbH (Dena) [104], EWI - Universität zu Köln [113], Bundesministerium für Wirtschaft und Technologie [114], European Commission [112] are used as a basis for Germany. The development in the Netherlands is based on reports by European Commission [112], Planbureau voor de Leefomgeving [115] and finally Belgium is based on the report by European Commission [112]. Installed WPP capacities are taken from the TradeWind project [116]. Future transmission capacities are based on the Ten-Year-Network-Development-Plan by ENSTO-E [117], the extensive study by Deutsche Energie-Agentur GmbH (Dena) [104] and individual projects, like the extension of the Skagerrak cable [53]. The consumption is mostly expected to stay constant, as the forecasts in the reports above mentioned were not consistent.

The following subsections give a detailed overview of assumptions for the 2010 and 2020 scenarios.

4.2.1 Transmission lines

Besides a transmission expansion inside countries, the expansion of cross-border transmission capacity is crucial in order to use power production sources efficiently and enable the large-scale integration of power production from renewable sources. Table 4.1 lists the transmission capacities of the HVDC cables connecting Nordic to continental Europe. Presented are the NTCs, stating the potential exchange capacities. In the 2020 scenario the new commissioning of the Nordlink cable and planned expansions on some of the interconnections [118] are included[3]. This expansion results in almost doubling of the interconnection capacity.

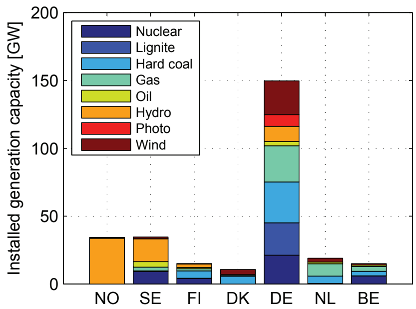
Table 4.1: NTCs of HVDC cables from Nordic to continental Europe in MW

	Area		2010		2020	
	from	to	from-to	to-from	from-to	to-from
NorNed	NO	NL	700	-700	1400	-1400
Nordlink	NO	DE	-	-	1400	-1400
Skagerak	NO	DK	850	-850	1550	-1550
Konti-Skan	SE	DK	485	-485	680	-740
Baltic	SE	DE	525	-400	600	-600
Storebælt	DK	DK	600	-600	600	-600
Kontek	DK	DE	550	-550	600	-600
Sum			3710	-3585	6830	-6890

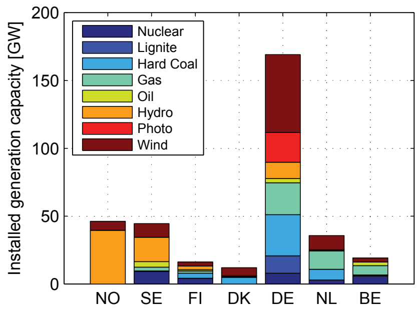
4.2.2 Power plant portfolio

Fig. 4.6 shows the installed power plant capacities in the modelled countries in 2010 and 2020. The future development is based on the decommissioning of old power plants, which will reach their maximum lifetime and the commissioning of new power plants. For the commissioning, only power plants, which are actually planned are regarded. The challenge is to give a good estimate on the expected capacity of nuclear power plants. In this analysis, it is assumed to be constant, apart from Germany, where the generation capacity is halved. This is in line with the current policies. To account for the large increase in WPP additional thermal capacity needs to be decommissioned. This is done by taking out about 30% of the lignite power plants in Germany and some of the hard coal power plants, which would have rather low running hours.

[3] The plans for new HVDC cables change constantly. At the time of the scenario development the extension of NorNed 2 was still regarded by Statnett SF [118].



(a) 2010



(b) 2020

Figure 4.6: Power plant portfolio per country in 2010 and 2020

The thermal power production is implemented in two different ways, either as scheduled production, for which a production profile is given, or as dispatchable production. The division of power plant types in scheduled and dispatchable production is shown in Table 4.2. However, some of the hard coal, gas and oil fired power plants are used for district heating, thus having a partly fixed production profile. The available dispatchable generation capacity is modelled in the form of single power plants with individual marginal production as well as start up and shut down costs.

Table 4.2: Classification of modelled thermal power plant types as dispatchable / non-dispatchable

Non-dispatchable generation	Dispatchable generation
Nuclear	Hard coal
CHP	Lignite
Biomass	Gas fired
	Oil fired

A detailed overview on the installed generation capacity in each of the countries is given in Tab. 4.5 and 4.6 in Appendix 4.6. In addition Fig. 4.21 and 4.22 show the resulting marginal cost curves of the production for one week in each of the countries for the 2010 and 2020 scenario respectively. WPP is bid at zero cost in this curves and hydro power production according to its water value. The cost curves illustrate, that the marginal production costs slightly decrease from 2010 to 2020, due to the expected increase in efficiency of the power plants.

Apart from the changes in the thermal plant portfolio, there are also some increases in hydro capacities in the Nordic area. The main increase is only in power plant capacity and not in reservoirs, which increases the plants flexibility. Thus, the hydro power plant has the ability to produce more when prices are high, without an increase in the total energy production. In addition some energy is expected from new small hydro production.

4.2.3 Wind power production

WPP is expected to be one of the main drivers for future changes in the power system. As shown in Fig. 4.6 a significant increase of installed WPP capacity is expected. The increase is estimated to be from about 34GW in 2010 to 96GW in 2020, corresponding to the high wind scenario in the TradeWind project [116].

To simulate WPP, two different wind production data sets are used. The first data set includes historic wind speed data of several years, provided from the TradeWind project [116]. Thus, the annual variation of WPP is taken into account. However, this data has a rather low spatial and temporal resolution (6h time steps and 2.5 degrees point-to-point distance). The second data set includes the hourly WPP data with a much higher geographic resolution (approx. 7 km), which is based on wind speed data from the COSMO EU model [119]. For the simulation of WPP over 3200 WPP facilities are included to model the geographical spread of WPP. The WPP is aggregated in each area, resulting in a smoothing of the power production from the single WPP facilities. A detailed explanation of the methodology can be found in [120]. However, due to its high grade of detail hourly WPP data is only available for one year, which is then used for all inflow scenarios.

For the fitting of the scenarios, the first data set is used, accounting for annual differences in WPP. However, as the day-ahead spot market outcome is used as the basis for the regulating power market, hourly WPP data is used for the final runs of EMPS. Moreover, for the hourly WPP data set also WPP forecasts are available, which are essential in the further research dedicated to regulating power markets.

4.2.4 Reserve requirements

As stated in section 4.1, EMPS includes the definition of start and stop costs for thermal power plants as well as reserve requirements for countries. Those are handled using a linearised approximation, similar to Warland et al. [101] and to the methodology used in the regulating power market model, described in Chapter 5. In EMPS only spinning upward reserves are regarded, which can be procured from hydro plants and running thermal power plants. The requirements for the 2010 and 2020 scenario used in EMPS are stated in Table 4.3. The increase of the reserve requirements is based on the increasing WPP, using the three-sigma approach, see also Holttinen et al. [121].

Table 4.3: Reserve requirements per country in MW

	NO	SE	FI	DK	DE	NL	BE
2010	2000	2020	865	1200	5800	300	150
2020	3000	2750	1050	1500	9400	1330	345

4.3 Simulation results

The previously defined 2010 and 2020 scenario are run with EMPS. The outcome of both scenarios is presented below. The simulations use 75 years of inflow and WPP for the strategy part. Due to the high level of detail and computational effort, only 10 different inflow years and hourly WPP is used during the simulation part. The presented results show these ten years.

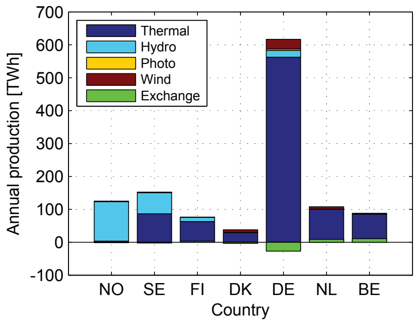
4.3.1 Generation mix

The resulting annual generation mix per country is drawn in Fig. 4.7 and given in Tab. 4.7 and 4.8 in the Appendix 4.6. It is divided between thermal, wind, photovoltaic and hydro power production, illustrating the shift of power production from fossil to renewable energy sources.

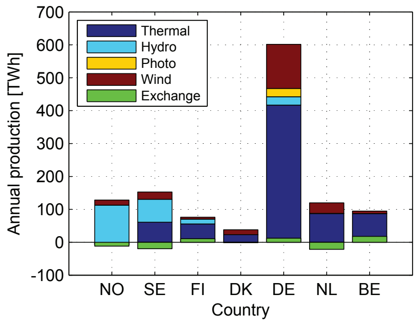
For 2010 the current generation mix is reproduced quite well, as it is one of the fitting criteria for the model. In Norway electricity production is almost 100% from hydro power plants, while Sweden has a share of about 50% of hydro prodcution. In Denmark and Germany there already is a noticeable share of WPP, suming up to 51TWh in total. The remaining power production is by thermal power plants from different sources and a small portion by photovoltaics.

In 2020 the generation mix changes noticeably. The main difference is the growing WPP in all countries according to the scenario assumptions, resulting in a WPP of 233TWh in total. Besides the rising WPP, there is a shift of power production between the countries. The total production increases in Sweden and especially the Netherlands and decreases in Germany. The shift is mainly due to the change in the portfolio of thermal power plants and an expected load increase in the Netherlands.

The change in the generation mix likewise has an impact on the exchange between the countries. Most noticeably is, that Germany turns from an electricity exporting country in 2010 to an importing country in 2020. Furthermore, there generally is an increasing export from the Nordic area in 2020.



(a) 2010



(b) 2020

Figure 4.7: Resulting generation mix per country

4.3.2 Operation of thermal power plants

As seen in the previous figures, there is a reduction in the power production from thermal power plants. This is due to less installed thermal capacity as well as decreasing operating hours of the thermal power plants. The operating hours for the thermal power plants grouped by type are plotted in Fig. 4.8 and Fig. 4.9. Only power plants which are assumed to be freely dispatchable are included. These are hard coal, gas- and oil-fired power plants.

In Fig. 4.8 data for the 2010 scenario is plotted. All of the hard coal power plants run more than 7000 hours, with most of them operating full time[4]. The operation hours are far less for gas-fired plants, as they have higher marginal production costs and thus are dispatched more seldom. It is even more the case for oil-fired power plants, where only a couple run for several thousand hours a year. Most of them are only dispatched for less than 500 hours.

[4]Outages of thermal power plants are taken into account by reducing the available thermal capacity in each individual week. The available capacity per week is based on published data at the European Energy Exchange[122].

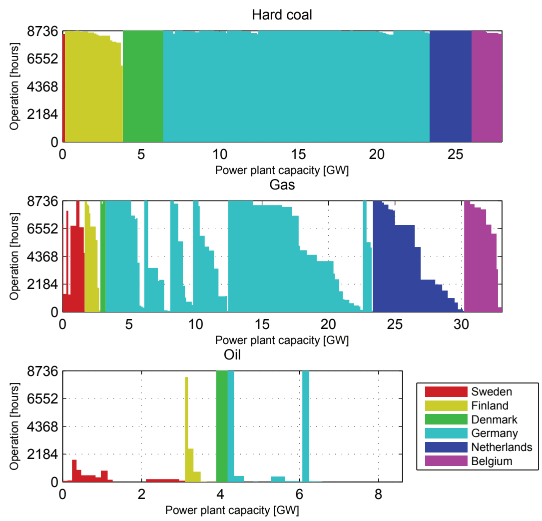


Figure 4.8: Operating hours of thermal power plants in 2010

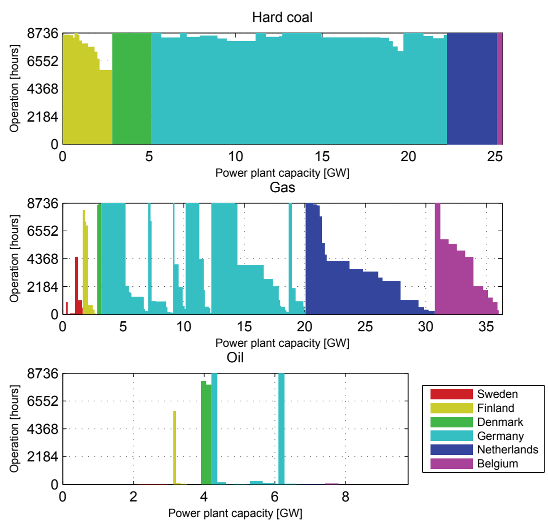


Figure 4.9: Operating hours of thermal power plants in 2020

Operating hours change in the 2020 scenarios, due to the increasing amount of intermittent WPP with zero marginal cost. There is a recognizable reduction for hard coal power plants with some plants running below 75% of the time. For gas-fired power plants this reduction is even higher with more than two-third of the installed capacity running below 50% of the time and a share of those running only about 1000 hours. For oil-fired power plants, there is no significant change. The annual short-term margin per installed capacity of thermal power plants (in €/kW), defined as the revenues minus the variable costs, are plotted in Fig. 4.10 and Fig. 4.11, for 2010 and 2020 respectively. This margin must also cover fixed costs like investment and maintenance. The low number of operating hours, especially for gas-fired power plants challenges their profitability. To be profitable these power plants have to recover their costs in only a limited number of peak-production hours. Open-cycle gas turbines with high marginal costs but low investment costs might be able to recover these during the occasional price spikes.

In general, between 2010 and 2020, not only running hours of the power plants are reduced, but also annual margins. For hard coal plants the reduction is about 20%, but for gas-fired power plants the margins are reduced by more than two-third. Oil-fired power plants do not have a positive margin in 2020 anymore, but in fact operate at a deficit. Losses can occur due to the implemented reserve requirements, which do not imply capacity payments to plant owners in the model. In reality, there has to be some form of payment for reserves, resulting in positive margins for peaking plants.

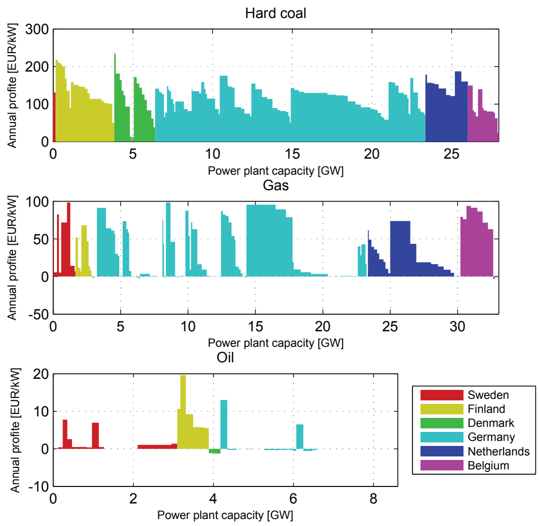


Figure 4.10: Margin of thermal power plants in 2010

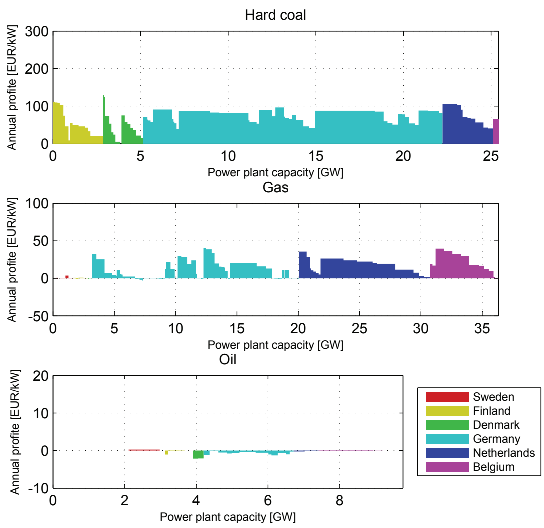
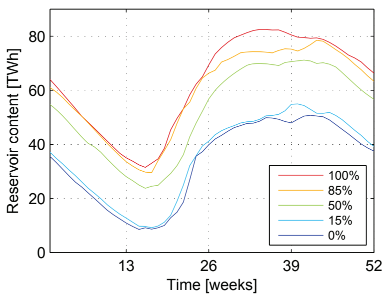


Figure 4.11: Margin of thermal power plants in 2020

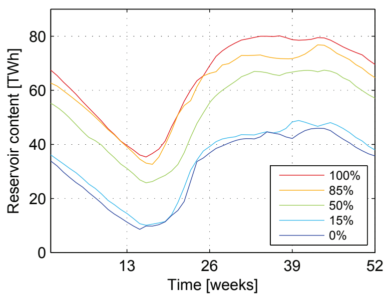
It is important to mention that reduced operating hours do not imply a reduction to zero, i.e. a power plant is never in operation. This indicates that keeping the thermal capacity is probably not profitable, but it is essential to have sufficient production capacity in the system to serve the load at any instance. Ensuring security of supply during peak demand and low wind production hours is a major challenge for the future power system, cf. the ongoing discussion on capacity payments [123].

4.3.3 Reservoir levels

Fig. 4.12 present the percentiles of the Norwegian reservoir levels during a year. The general characteristic, is an emptying of the reservoirs during winter and early spring and the filling up during late spring and summer. There are significant differences between wet and dry years. The total installed reservoir capacity in Norway is about 86TWh, which is nearly reached in the wettest year in 2010. This maximum level is lower in the 2020 scenarios. One of the differences in the 2020 scenario is that the mean reservoir level is higher than in 2010. Further the difference between the percentiles increases, thus the percentiles get flatter. This indicates a decreasing utilization of the long-term energy storage possibility of hydro-reservoirs. However, these percentiles are not suitable for the analysis of the short-term flexibility of the hydro production. This would be interesting to display the impact of increasing WPP, where storage on hourly or daily basis is necessary.



(a) 2010



(b) 2020

Figure 4.12: Norwegian reservoir levels

4.3.4 Transmission

To analyse the short-term flexibility of the power production, the transmission dispatch between Nordic and continental Europe is meaningful, shown in Fig. 4.13. Plotted is the average transmission dispatch for the whole transmission corridor, including all of the transmission lines presented in Table 4.1. The dotted black lines, indicate the minimum and maximum capacity. It shows that the volatility of the transmission dispatch is much higher in 2020 than in 2010, showing an increasing flexibility of the Nordic hydro production.

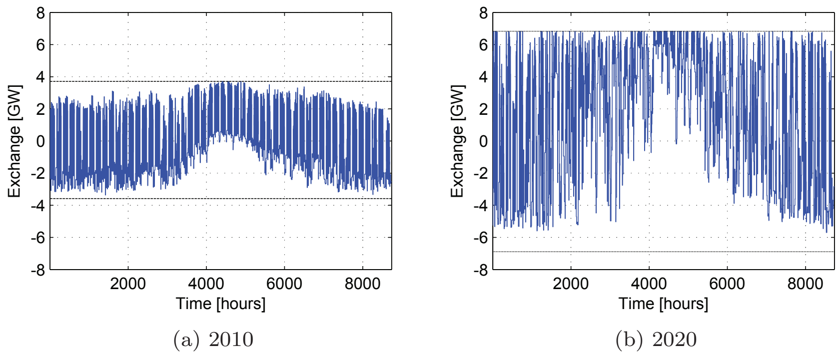


Figure 4.13: Day-ahead transmission dispatch Nordic to continental Europe

With the increased capacity of the corridor comes an increasing exchange between Nordic and continental Europe. The average annual values are given in Table 4.4. In 2010 in Fig. 4.13a a regular exchange pattern can be observed, with a high export during summer time, resulting from a low consumption and high hydro production in the Nordic system. Furthermore, the average export and import of energy from the Nordic area are almost counterbalanced. This results in a net export of only 476GWh, see Table 4.4. However, there are significant differences between inflow scenarios. In a wet year the net export is as much as 13.1TWh, whereas in a dry year 11.5TWh are imported. Evaluating the different cables, it can be seen that there is a relatively high export on the cables from Norway to continental Europe (NorNed and Skagerrak), while Sweden imports electricity from continental Europe.

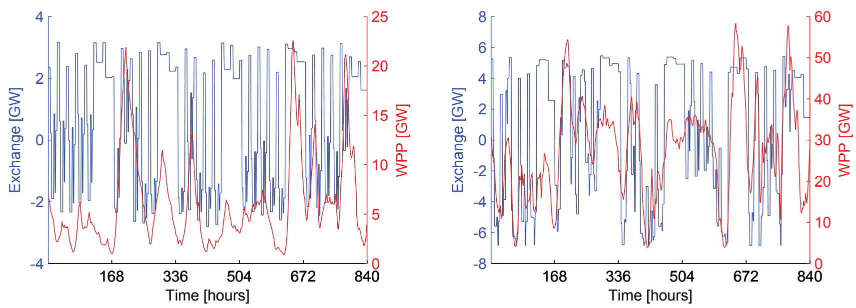
In 2020 the transmission dispatch changes significantly. The main difference is that there now is a net export of energy to continental Europe of about 16.2TWh in average. Due to the increasing transmission capacity the gross exchange energy is nearly 75% higher compared to 2010.

Fig. 4.14 shows five weeks of exchange from continental to Nordic Europe

Table 4.4: Average annual transmission from Nordic to continental Europe in GWh

	2010		2020	
	net	gross	net	gross
NorNed	693	4845	3584	8350
Nordlink	-	-	2943	8464
Skagerrak	959	4881	3638	5108
Konti-Skan	7	2915	1655	4698
Baltic	-203	2999	1192	4127
Storebælt	-25	866	1196	2255
Kontek	-956	3367	2038	4004
Overall	476	19083	16246	36171

together with continental WPP[5]. There are two main differences between 2010 and 2020. Firstly, in 2010 there is only a minor relation between the exchange and WPP. On the Contrary in 2020, there is a strong influence of WPP on the transmission. During high WPP there is a higher export of energy from continental to Nordic Europe and vice versa. The second difference is the exchange pattern. A distinct pattern can be observed in 2010, with export from the Nordic area during day-time and import during night and the weekends. In 2020 a pattern can still be observed. However, it is largely disturbed by WPP.

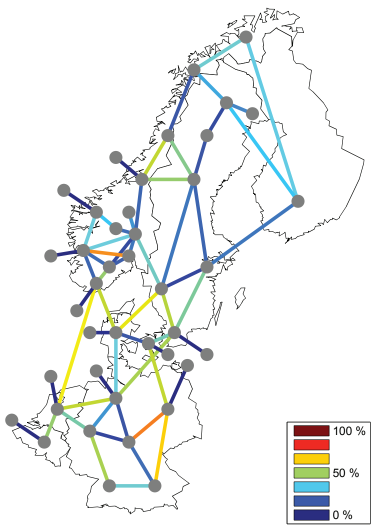


(a) 2010 (b) 2020

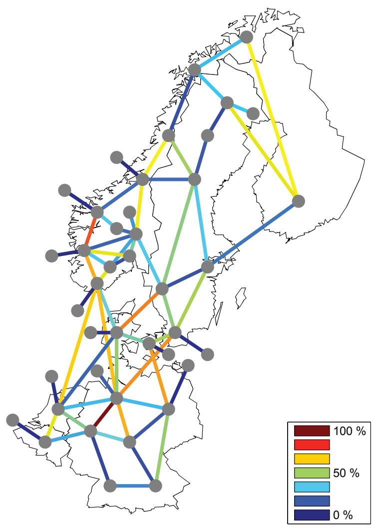
Figure 4.14: Comparison transmission dispatch continental to Nordic Europe (blue) and continental WPP (red) for 5 weeks

[5]The exchange direction is inverted compared to the previous diagrams, as it now illustrates the dependency between the exchange and the WPP more clearly.

Fig. 4.15 shows the annual utilization of the individual transmission lines. The utilization of a transmission line is the ratio between gross transmitted energy and the available transmission capacity. In 2010 besides the Storbælt cable the utilisation of the HVDC cables is 50% to 60%, whereat the NorNed cable has the highest value. Furthermore, there are country internal cables with a quite high utilisation, indicating potential congestions.



(a) 2010

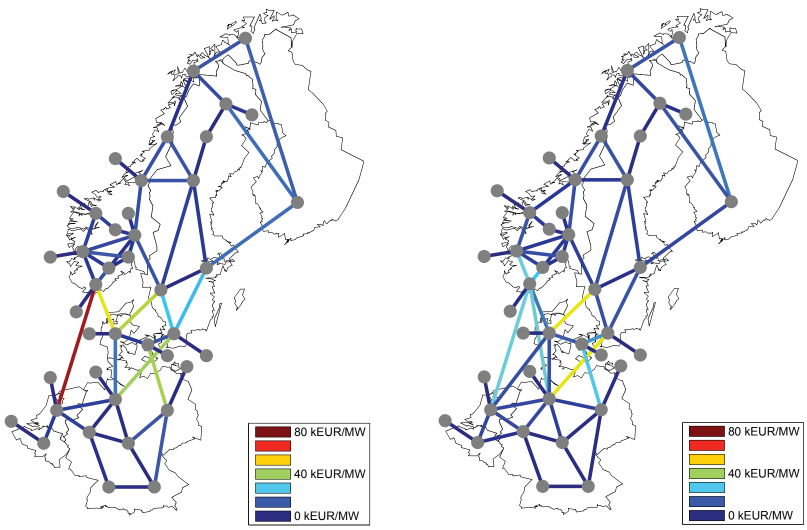


(b) 2020

Figure 4.15: Transmission corridor utilization in percentage of installed capacity

Fig. 4.16 shows the annual revenues per installed MW of the transmission corridors, which is determined by the price difference between both ends multiplied with the transmitted energy. These revenues are also a rough indicator for the marginal benefit of a transmission line to the society. It clearly shows, that the HVDC-connections create significant revenues in 2010, especially the NorNed cable.

In spite of the increasing transmission capacity, the average utilisation reaches more than 60% in 2020 for most of the HVDC-connections (see Fig. 4.15b). The revenues per MW of the HVDC-lines decrease significantly compared to 2010. However, the connections between Nordic and continental Europe still generate the highest revenues, indicating their benefit to the European society. Beside these connections, both internal corridors to Southern Norway, show high revenues, indicating congestions and the high importance of the lines.



(a) 2010

(b) 2020

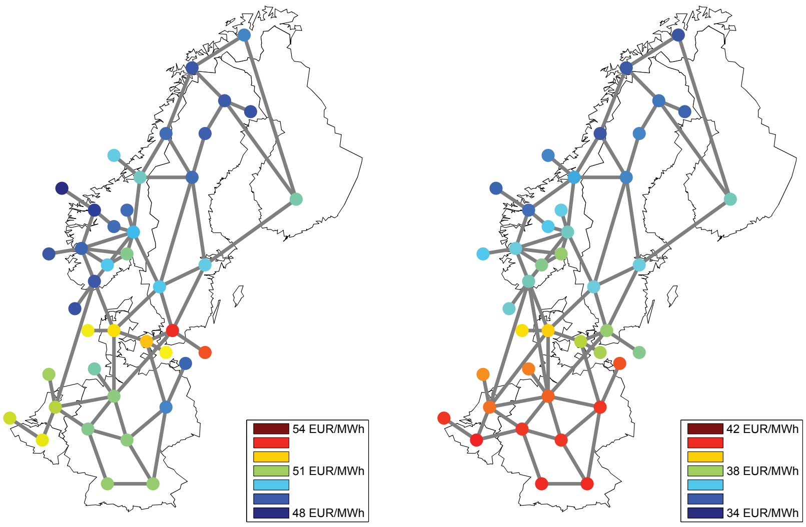
Figure 4.16: Average annual transmission corridor revenue per installed MW

4.3.5 Area prices

Beside the optimal dispatch of the power system, EMPS provides marginal prices for each area. An overview of the average annual price per area is given in Fig. 4.17. The diagram shows the current characteristics with low prices in the Nordic area and higher prices on the continent. However, there are some exceptions, which are Southern Sweden and Eastern Germany. Prices differ here due to congested lines. These price differences are not seen in the market, because Sweden as well as Germany are defined as one price area in the presented markets[6]. In 2020 there is a decrease of the average price and a consistent course with low prices in the north to high prices in the south.

Fig. 4.18 and Fig. 4.19 depict prices in Norway and Germany as percentiles of the inflow scenarios. In EMPS, countries consist of several areas, which normally do not have one single price for the whole country. Thus the price for the country is calculated by a weighted average, where weighting is done by the annual consumption of each area. Norway and Germany are chosen as they represent a typical hydro and a thermal production system. Furthermore, there is a significant amount of new WPP capacity in Northern Germany, having an impact on the prices.

[6]Sweden was divided into four price areas in November 2011 [97].



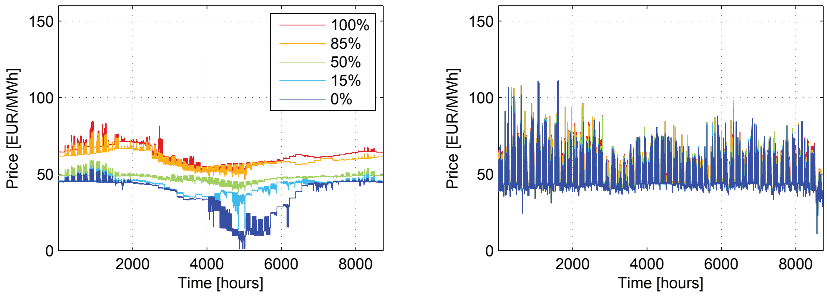
(a) 2010 (b) 2020

Figure 4.17: Average area electricity prices in EUR/MWh

Fig. 4.18 shows percentiles of the prices for 2010, where the characteristics of each of the countries can be seen clearly. In the Norwegian hydro based system (Fig. 4.18a), there is a difference in the long-term behaviour of day-ahead prices, due to different inflows to the hydro system in the different years[7]. However, prices do not vary much from one hour to the next. In the German thermal based system (Fig. 4.18b) an opposite behaviour can be seen, as there is no energy constrain due to inflow. But there are big differences between sequential hours, e.g. peak, off-peak and night hours. These differences are due to different fuel types of the thermal power plants resulting in different marginal production and start/stop costs. The yearly average price of both countries is similar, being about 50€/MWh. In both countries higher prices are observed during late winter and early spring time and low prices in the summer. Furthermore, a dip is noticeable in the thermal system during Christmas due to the country-wide holiday season.

The prices for the 2020 scenario are depicted in Fig. 4.19. The general development is different for both countries. In Norway differences between the years diminish, i.e. the inflow to the hydro system has less impact on electricity prices, induced by the stronger interconnections with the continental system.

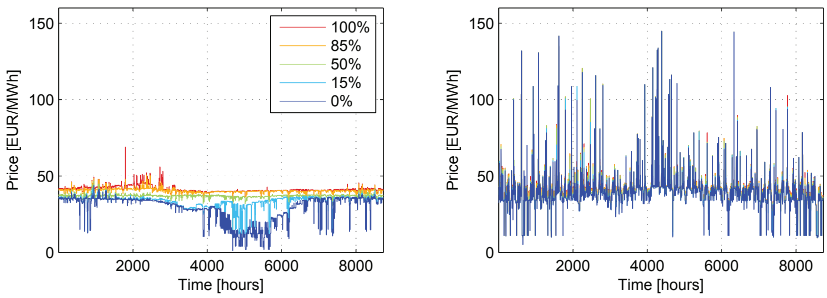
[7]During wet years with high inflow, prices are low due to excessive hydro production. In contrary, during dry years with low inflow, prices become high.



(a) Norway (b) Germany

Figure 4.18: Percentiles of day-ahead electricity prices in 2010

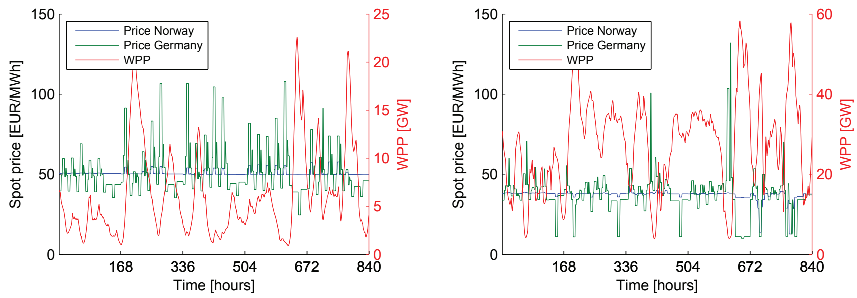
Furthermore, the average of prices decreases from 47€/MWh to 35€/MWh. The day-ahead price reduction also occurs in Germany, with an average price of about 40€/MWh. In addition, the regularity of the price pattern vanishes and irregular price spikes emerge. Beside price spikes there are price dips, which occur in cases of excessive WPP, mostly seen during winter time.



(a) Norway (b) Germany

Figure 4.19: Percentiles of day-ahead electricity prices in 2020

A more detailed view on the prices in Norway and Germany is given in Fig. 4.20, showing five weeks of a regular year. In addition to the prices the continental WPP is plotted. The above mentioned changes in price characteristics are illustrated in these plots. In 2010 there is a quite clear day and night pattern in Germany. This pattern is disturbed by the increased WPP in 2020. The dependency between WPP and prices emerges in Germany in 2020, i.e. low prices during high wind periods and high prices during low wind periods. However, these price changes do not influence Norwegian prices significantly.



(a) 2010 (b) 2020

Figure 4.20: Comparison day-ahead country electricity prices and continental WPP for 5 weeks

4.4 Discussion

As an initial observation, it must be taken into account that the model is a long-term operation optimisation model and not an investment optimisation model. Investment, i.e. decommissioning and commissioning of power plants and transmission lines is exogenous to the model. Especially with the high increase of WPP capacity, the available capacity of thermal power plants in 2020 may be overestimated in the model, resulting in the low operating hours of the thermal power plants. However, operating hours do not decrease to zero, indicating the necessity for this thermal capacity.

An arguable simulation outcome are the decreased average prices of electricity in the 2020 scenario, which were also observed in an ELMOD study [124]. The decrease occurs due to several reasons. Firstly, fuel prices are kept constant. Combined with expected increased efficiency of power plants, lower marginal production costs occur. Keeping fuel prices constant is done to allow comparability between the 2010 and 2020 scenario. Moreover, due to the significant uncertainty of future fuel prices, it is difficult to make a realistic forecast of such prices in 2020. As a results of the increased WPP in 2020 and the displacement of more expensive thermal power plants by WPP, cheaper ones set the marginal costs more often.

4.5 Conclusion

The long- and mid-term operation optimisation model EMPS is used to analyse the Northern European power market outcome in 2010 and 2020. In 2020 a significant share of WPP capacity is expected in the system, likewise resulting in a significant share of electricity production from that source. The power plant portfolio and transmission capacities are updated based on referred studies. Although some thermal capacity is assumed to be decommissioned in 2020, a substantial quantity of thermal generation is still available.

The simulations show, that there are significant changes in the system up to 2020. There is a substantial reduction in the operating hours of thermal power plants, challenging their profitability. Due to the increasing transmission capabilities, the energy exchange between Nordic and continental Europe increases drastically, (almost doubled in 2020). The analyses show that in 2010 as well as in 2020 the transmission lines generating the highest revenues are the connections between Nordic and continental Europe, which is also a measure for their benefit to the society.

Comparing electricity prices in 2010 and 2020, several differences can be observed. Firstly, average prices are reduced. Secondly, the stronger interconnections between the Nordic and the continental system reduce the impact of the stochastic inflow, i.e. the differences between inflow years in the Nordic system. In the thermal system the diurnal pattern with high peak and low night prices vanishes. Instead a higher price volatility with random peaks and dips occurs, resulting from the increased amount of variable WPP.

4.6 Appendix

Table 4.5: Installed generation capacity per type and country in 2010 [MW]

	Norway	Sweden	Finland	Denmark	Germany	Netherlands	Belgium
Nuclear	0	9352	4256	0	21251	485	6050
Lignite	0	0	0	0	23893	0	0
Hard coal	0	340	4612	5566	30056	5364	3348
Gas	0	2710	1645	723	26657	9058	3612
Oil	0	4084	973	520	3160	1285	965
Photo	0	0	0	0	8600	0	0
Wind	545	1250	350	3700	24900	2800	1000
Hydro	33800	16900	2450	0	11200	0	0

Table 4.6: Installed generation capacity per type and country in 2020 [MW]

	Norway	Sweden	Finland	Denmark	Germany	Netherlands	Belgium
Nuclear	0	9352	4256	0	8000	2985	6050
Lignite	0	0	0	0	12780	0	0
Hard coal	0	340	3715	4918	30318	7882	694
Gas	0	2710	1645	597	23494	13583	6812
Oil	0	4114	973	520	3160	819	2765
Photo	0	0	0	0	22000	0	0
Wind	6600	10000	3000	6000	57300	10400	2950
Hydro	39600	18000	2700	0	12000	0	0

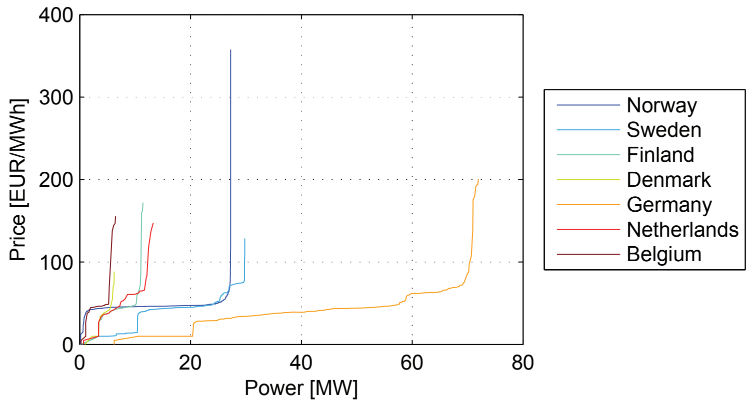


Figure 4.21: Marginal cost curve for production per country in week 13 in 2010

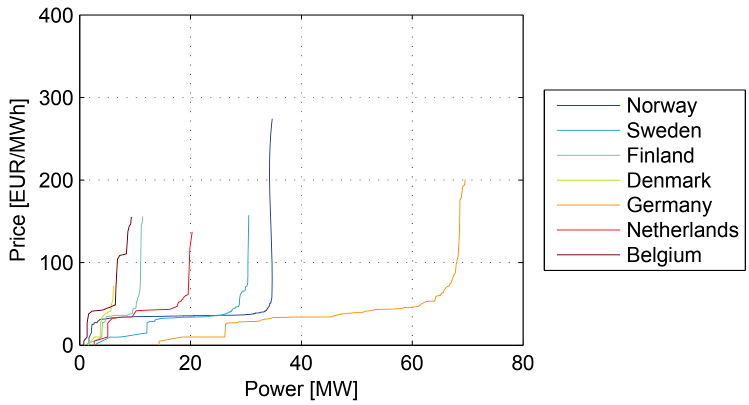


Figure 4.22: Marginal production cost curve per country in week 13 in 2020

Table 4.7: Demand and generation mix per country in 2010 [GWh]

	Norway	Sweden	Finland	Denmark	Germany	Netherlands	Belgium
Demand	115367	152499	76400	38096	616800	108001	8826
Thermal	0	88702	59626	33654	589443	92351	75156
Wind	0	0	0	0	4380	0	0
Photo	1710	1387	581	7885	29570	7109	2427
Hydro	119691	64107	13004	0	20419	0	0

Table 4.8: Demand and generation mix per country in 2020 [GWh]

	Norway	Sweden	Finland	Denmark	Germany	Netherlands	Belgium
Demand	115367	152499	76400	38096	601377	120001	95000
Thermal	0	78652	43885	22861	405267	114706	67585
Wind	0	0	0	0	25000	0	0
Photo	15535	22407	5985	14880	134121	32275	7649
Hydro	119625	69203	15037	0	25500	0	0

Chapter 5

IRiE - The regulating power market model

The chapter presents the regulating power market model, called "Integrated Regulating power market in Europe" (IRiE[1]). It simulates the procurement of reserve capacity and the real-time system balancing. In addition, the chapter includes an example of the application of IRiE, containing an analysis of regulating power market integration. The chapter is based on **Publication B** and its succeeding **Publication C**. The former publication contains the mathematical description of the regulating power market model, excluding transmission availability aspects for cross-border reserve procurement. This issue is dealt within the latter publication.

Section 5.1 presents the methodology and the full mathematical description of the regulating power market model, while the model's notation is given in the Appendix of this chapter. Section 5.2 to 5.5, which contain the analysis, are identical to Sections 4 to 7 of **Publication C**, with minor editorial changes.

5.1 Modelling

IRiE is based on linear and mixed-integer programming. It is implemented in AMPL [126], using the CPLEX[2] and GUROBI[3] solvers for the optimization.

[1] irie: to be at total peace with your current state of being [125].
[2] http://www.ibm.com/software/integration/optimization/cplex-optimizer/
[3] http://www.gurobi.com/

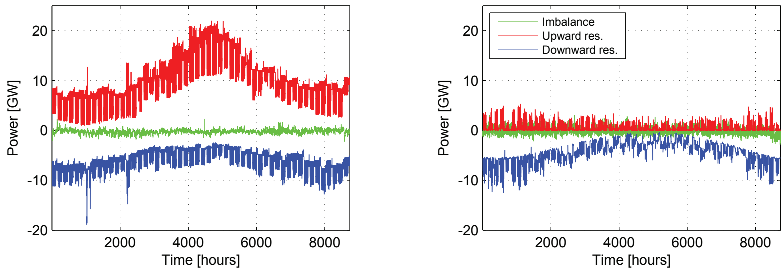
5.1.1 Day-ahead spot market results

The outcome of the day-ahead spot market, which is simulated with EMPS, is presented in the previous chapter 4. These simulations already treated requirements for regulating reserves on a simplified level. The requirements are included to achieve realistic results of the day-ahead market clearing. However, in the following regulating power market model, the procurement of reserves, i.e. reserve requirements are treated explicitly. Thus, the basis for the regulating power market model are detailed day-ahead market simulations with reserve requirements set to zero. Some results from these day-ahead spot market simulations, which are essential for the succeeding regulating power market simulation, are presented in the following.

Available reserve capacity

With reserve requirements set to zero, still a certain amount of reserve capacity is available in the system. Fig. 5.1 shows the freely available reserve capacity during one year in Norway (Fig. 5.1a) and in Germany (Fig. 5.1b). Available upward reserve capacity is plotted in red, downward reserve capacity in blue. In addition recorded system imbalances are plotted in green. These plots are based on day-ahead spot market simulations, without the implementation of reserve requirements and using the definition of reserve capacity, as defined in succeeding section 5.1.2. During summertime, upward reserve capacity is certainly overestimated in Norway, as the maintenance of hydro power plants is not regarded. Furthermore, the plot shows the sum of all reserve capacities within the countries, disregarding constraints in the transmission grid.

However, the plot illustrates several important issues. Firstly, in the hydro power based Norwegian system, often a sufficient amount of reserve capacity is available in order to handle imbalances. Only during winter and early spring a procurement of reserves is necessary, to safeguard sufficient reserves. Secondly, in the German thermal based power system, there are numerous instances, where system imbalances would exceed the freely available reserve capacity. Thus, a procurement of reserves is necessary all the time. The procurement is necessary for upward as well as downward reserve capacity. Finally, during periods with excessive reserve capacity in the Norwegian power system, a share of the reserve capacity could be provided to the German power system.



(a) Norway (b) Germany

Figure 5.1: Available upward and downward reserve capacity after day-ahead spot market clearing vs. system imbalance

Transmission dispatch

Fig. 5.2 shows the day-ahead dispatch of the transmission corridor[4] from RGN to RG CE. It illustrates, that there is plenty of transmission capacity available on the corridor after the day-ahead spot market clearing, which can be used for cross-border procurement of reserve capacity and the exchange of balancing energy, as suggested in Chapter 2. The plot shows the percentiles of the annual duration curve for the transmission dispatch in the different inflow years. Furthermore, the exchange strongly depends on the inflow to the Nordic hydro power system, also described in Chapter 4. However, only during 200 hours in a wet year, the transmission lines are coevally congested in one direction. But also during these hours, the cross border procurement of reserve capacity and an exchange of balancing energy is possible in the reverse direction.

Hydro power plant definition

Hydro power production is modelled in high detail in EMPS, including full water courses (see Fig. 4.1). The individual hydro power plants are modelled with a piece-wise linear production-discharge curve. As described in Chapter 4, the discharge is calculated in the equivalent energy, using the energy conversion factor[5].

[4]Transmission corridor refers to the sum of all transmission lines. These lines include all the HVDC lines presented in Table 4.1, which connect RGN to RG CE.

[5]The energy conversion factor is defined for every hydro module, taking into account the head-height and the average efficiency of the discharging hydro power plant. As the average efficiency is used to determine the conversion factor, the actual output of a hydro power plant can be higher than the equivalent energy discharged from a reservoir. This causes an marginal production efficiency higher than 1.0.

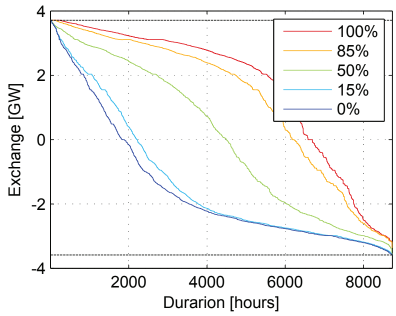


Figure 5.2: Percentiles of the duration curves of the day-ahead transmission dispatch from RGN to RG CE for hydro inflow scenarios

An example for a production-discharge curve is shown in Tab. 5.1. The presented hydro power plant has an energy conversion factor of 0.0783 kWh/m^3. The discharge of equivalent energy is calculated by:

$$z(V) = V \cdot 0.0783 \frac{kWh}{m^3} \cdot 3600 \frac{s}{h} \tag{5.1}$$

Table 5.1 shows the production of the power plant y with the according discharge, given in volume of water V and in terms of the equivalent energy z. The left side of the table shows the linear production-discharge curve, while the ride side contains their single linear pieces. The last column of the table presents the marginal efficiency η_p for each of the linear pieces p.

The marginal efficiency is calculated by the ratio between the equivalent energy discharge and the production of each linear piece, see Equation 5.2.

$$\eta_p = \frac{y_p^{hp}}{z_p} \tag{5.2}$$

Equation 5.3 defines the total production y_h^{hyd} of a hydro power plant h as the sum of its single linear pieces $(p \in P_h)$.

$$y_h^{hyd} = \sum_{p \in P_h} y_p^{hp} = \sum_{p \in P_h} \left(z_p^{hp} \cdot \eta_p \right) \tag{5.3}$$

Finally, the production cost C_h^{hyd} of a hydro power plant h is stated in Equation 5.4. The cost is the equivalent energy discharge multiplied with the water value $v_{a,\omega}$ of the reservoir. This equals the production of each linear piece divided by the marginal efficiency times the water value.

Table 5.1: Example of a production-discharge curve as defined in EMPS

Linear curve			Linear pieces		
Water discharge V $[m^3/s]$	Energy discharge $z(V)$ $[MWh/h]$	Production $y(V)$ $[MWh/h]$	Energy discharge z_p^{hp} $[MWh/h]$	Production y_p^{hp} $[MWh/h]$	Marginal efficiency η_p
0	0	0			
			22.55	23.17	1.027
80	22.55	23.17			
			16.91	16.81	0.958
140	39.46	39.98			
			5.64	4.98	0.973
160	45.10	44.87			
			11.27	10.76	0.954
200	56.37	55.63			
			28.19	21.75	0.771
300	84.56	77.38			
			19.64	10.53	0.533
370	104.2	87.91			

$$C_h^{hyd} = \sum_{p \in P_h} z_p^{hp} \cdot v_{a,\omega} = \sum_{p \in P_h} \left(y_p^{hp} \cdot \frac{v_{a,\omega}}{\eta_p} \right) \tag{5.4}$$

The term $\frac{v_{a,\omega}}{\eta_p}$ represents the marginal production cost of each linear piece for a hydro production plant, given the water value and the marginal efficiency.

As shown in Tab. 5.1, the marginal discharge curve is not strictly increasing, due to the non-convexity of the production-discharge curve. To handle this non-convexity, the day-ahead dispatch of hydro power plants is determined by a rule-based approach in EMPS, cf. Wolfgang et al. [98]. For the implementation of a linear problem, the convexity is necessary. Thus, before running the regulating power market model the day-ahead dispatch is converted in a dispatch with strictly increasing marginal production costs, by sorting the linear pieces according to their marginal efficiency. The piece-wise linear representation of the hydro power plants is used in the following regulating power market model.

5.1.2 Reserve procurement

After the day-ahead spot market clearing, required reserve capacity is procured, see Fig. 3.1. The procurement is done by a redispatch of the generation and transmission. The approach of reserve procurement in the model is different from the reserve capacity markets run in the Northern European countries, as described in Chapter 2. The reserve capacity markets are normally run prior to day-ahead spot markets, detracting production capacity from the day-ahead spot market, in order to ensure that enough reserve capacity is available during real-time operation of the power system.

In the presented model a perfect market is assumed, hence all available production capacity is bid into the markets, the day-ahead spot as well as the regulating power market. Thus, it is assumed that withdrawing production capacity from the day-ahead spot market beforehand does not differ from procuring the reserve capacity through redispatch afterwards. The only difference in procuring reserve capacity after day-ahead spot market clearing is, that the marginal production capacity is always chosen for the provision. If reserve capacity is procured prior to the day-ahead spot market clearing, the procurement has to be based on an expected day-ahead spot market outcome, cf. Just and Weber [66]. Thus, it is not ensured that marginal power plants are chosen to provide the reserve capacity. The sequence chosen in this model can be interpreted as the socio-economic most beneficial approach or an idealized reserve procurement. The implemented approach gives the lower boundary of procurement costs, which are implied by set reserve requirements. This potentially results in a too low reserve procurement cost estimation, when compared with costs occurring in the real regulating power markets.

Reserve definition

In the model procured reserves comprise spinning upward and downward regulation. The definition of spinning reserves used throughout the presented research is illustrated in Fig. 5.3. There is a distinction between hydro and thermal power plants providing reserve capacity. For hydro power plants it is assumed that start up and stop costs can be neglected, they can be started up immediately and no minimum production is required. Thus, their full generation capacity can be used as reserve capacity and hydro power plants do not need to be started up in order to provide reserves.

However, the start up and stop costs of thermal power plants are not negligible. They need longer time to start up and have a minimum production level. Hence, only thermal power plants that are started up and consequently produce above their minimum production level can provide spinning reserves. Spinning upward reserves can be provided up to the power plant's maximum production capacity (P_{max}). On the other hand, spinning downward reserves can only be provided down to the minimum production level (P_{min}) of a thermal power plant, as depicted in Fig. 5.3. The remaining production capacity of thermal power plants is defined as non-spinning reserve capacity, to make all generation capacity available during system balancing.

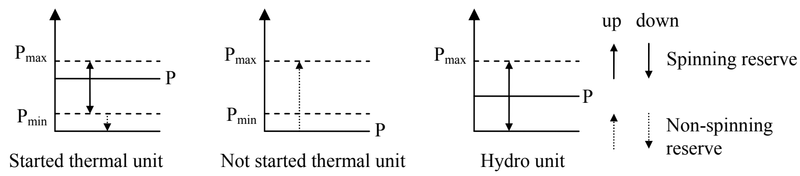


Figure 5.3: Definition of spinning and non-spinning reserves

In order to define the reserve requirements, the day-ahead areas implemented in EMPS (see Chapter 3) are aggregated, according to current control areas[6]. The reserve requirements for the control areas are shown in the following Table 5.2. The values chosen as the reserve requirements used as a basis throughout this thesis are the current requirements for FADR in RGN and the requirements for secondary control in the RG CE. These requirements are adapted according to different assumptions in succeeding analyses.

Table 5.2: Reserve requirements for countries in RGN and RG CE in MW (in 2010)

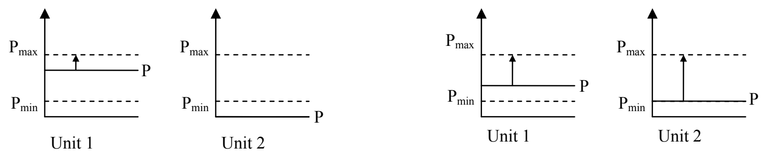
	DK-E	NO1	NO2	NO3	SWE	FIN	
Upward	580	1200			1220	865	
Downward	-580	-1200			-1220	865	

	DK-W	DE1	DE2	DE3	DE4	NL	BE
Upward	620	640	830	1000	540	300	150
Downward	-620	-400	-590	-725	-330	-300	-150

To fulfil the given reserve requirements, the day-ahead dispatch of generation and transmission has to be adapted. Two examples of such a redispatch are exemplified hereafter. The generation redispatch for the procurement of upward and downward reserves is illustrated with sketches in Fig. 5.4 and Fig. 5.5

[6] In reality Nordel is operated as one control area, with ACE being abolished. However, reserve requirements are defined for each country.

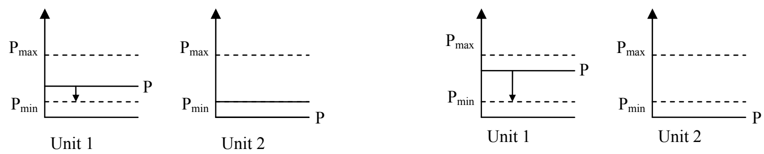
respectively. In these examples power plant 1 is the cheaper and power plant 2 the more expensive one.



(a) Before Procurement (b) After Procurement

Figure 5.4: Upward reserve procurement

Prior to the reserve procurement (Fig. 5.4a) in the first case, there is insufficient upward reserve capacity available. To fulfil the requirements, plant 2 has to be started up. Regarding the minimum production capacity, plant 2 has to be started up at least to its minimum level. Simultaneously the production has to be decreased on plant 1, see Fig. 5.4b. Consequently, the production costs increase due to the higher marginal production costs of plant 2, additional start up costs for plant 2 and higher production costs due to reduced efficiency on plant 1.



(a) Before Procurement (b) After Procurement

Figure 5.5: Downward reserve procurement

In the second case (Fig. 5.5a) there is insufficient downward reserve capacity prior the reserve procurement. This situation periodically occurs during off-peak periods, when some of the dispatchable power plants are still in operation at minimum production capacity to avoid additional shut down and resulting start up costs. To procure additional downward reserves, one of the plants has to be shut down. In this case power plant 2 is shut down, the one with higher marginal costs. The shut down results in an increased production of plant 1, providing sufficient downward reserve capacity. In this case the cost for procuring the required reserve capacity contains the additional shut down and start up costs for power plant 2.

Reserve procurement model

Consecutively, the mathematical description of the developed regulating power market model for the reserve procurement is presented. As a simplification it is assumed that during the reserve procurement procedure the generation dispatch, area prices and water values are known for the whole week. Due to the accounting for the start up state of the thermal power plants, there is a temporal dependency between single PTUs. However, this dependency is only between one and the next PTU. As there is a quite stable dispatch pattern during a week (cf. chapter 4), a perfect knowledge is assumed.

The objective of the reserve procurement procedure is to change the given day-ahead dispatch in a cost-effective way, in order to allocate sufficient upward $r_a^{\uparrow}$ and downward reserve capacity $r_a^{\downarrow}$ in each area ($a \in A$) to the fulfil given reserve requirements. The reserve procurement is modelled as a mixed-integer optimisation problem, on a weekly basis including all PTUs. A comprehended notation is given in the appendix 5.6.

Reserve requirements Reserve requirements are defined for each control area $r_k^{\uparrow r}$, $r_k^{\downarrow r}$ and for the whole system $r^{\uparrow r}$, $r^{\downarrow r}$. The according requirement constraints are defined in equations 5.5 to 5.8.

The sum over all reserve capacity ($r_{a,\omega,\tau}^{\uparrow}$, $r_{a,\omega,\tau}^{\downarrow}$) provided in an control area k plus reserve capacity, which is procured cross-border ($e_{l,\omega,\tau}^{\uparrow}$, $e_{l,\omega,\tau}^{\downarrow}$) must equal the given requirements at least.

$\forall k \in K,\, \omega \in W,\, \tau \in T$:

$$r_k^{\uparrow r} \cdot s^r \leq \sum_{a \in A_k} \left(r_{a,\omega,\tau}^{\uparrow} + \sum_{l \in L_a^f} e_{l,\omega,\tau}^{\uparrow} - \sum_{l \in L_a^t} e_{l,\omega,\tau}^{\uparrow} \right) + r_{k,\omega,\tau}^{\uparrow red} \tag{5.5}$$

$$r_k^{\downarrow r} \cdot s^r \leq \sum_{a \in A_k} \left(r_{a,\omega,\tau}^{\downarrow} + \sum_{l \in L_a^f} e_{l,\omega,\tau}^{\downarrow} - \sum_{l \in L_a^t} e_{l,\omega,\tau}^{\downarrow} \right) + r_{k,\omega,\tau}^{\downarrow red} \tag{5.6}$$

Equations 5.5 and 5.6 define the requirement constraints for each control area. The factor s^r determines the share of reserve capacity, which has to be procured within the same control area. Suggested by ERGEG [11] is a share of 67% of secondary reserves and 50% for the sum of secondary and tertiary reserves. The suceeding analyses use the lower share of 50% in order to promote the exchange of balancing services.

In addition to the reserve provision, $r^{\uparrow red}_{k,\omega,\tau}$ and $r^{\downarrow red}_{k,\omega,\tau}$ introduce a possible rationing of reserve capacity to ensure the feasibility of the solution. This rationing of reserves is comparable to situations in reality, when TSOs operate outside the requirements, therefore violating operational rules, but supplying all costumers[7].

For the whole system the sum of available reserve capacity has to be equal or higher than the sum of the reserve requirements, including the possible rationing of reserve capacity in single control areas.

$\forall \omega \in W,\ \tau \in T$:

$$r^{\uparrow r} \leq \sum_{a \in A} r^{\uparrow}_{a,\omega,\tau} + \sum_{k \in K} r^{\uparrow red}_{k,\omega,\tau} \tag{5.7}$$

$$r^{\downarrow r} \leq \sum_{a \in A} r^{\downarrow}_{a,\omega,\tau} + \sum_{k \in K} r^{\downarrow red}_{k,\omega,\tau} \tag{5.8}$$

$$0 \leq r^{\uparrow red}_{k,\omega,\tau}\ ,\ 0 \leq r^{\downarrow red}_{k,\omega,\tau} \tag{5.9}$$

Provision of reserve capacity The constraints for the upward $r^{\uparrow}_{a,\omega,\tau}$ and downward $r^{\downarrow}_{a,\omega,\tau}$ reserve capacity, which are available in an area are stated in equation 5.10 and 5.11. Reserve capacity can be provided from hydro and thermal power plants, which are situated in the according area.

$\forall \omega \in W,\ \tau \in T,\ a \in A$:

$$r^{\uparrow}_{a,\omega,\tau} = \sum_{g \in G_a} r^{\uparrow th}_{g,\omega,\tau} + \sum_{h \in H_a} \sum_{p \in P_h} \left(\overline{y}^{hp}_{p} - y^{hp^P}_{p,\omega,\tau} \right) \tag{5.10}$$

$$r^{\downarrow}_{a,\omega,\tau} = \sum_{g \in G_a} r^{\downarrow th}_{g,\omega,\tau} + \sum_{h \in H_a} \sum_{p \in P_h} \left(y^{hp^P}_{p,\omega,\tau} - \underline{y}^{hp}_{p} \right) \tag{5.11}$$

Hydro power plants The redispatch constraint of hydro power plants together with their production limit are defined by equation 5.12 and equation 5.13 respectively. $y^{hp^P}_{p,\omega,\tau}$ represents the generation dispatch for each linear piece of a hydro power plant after the procurement of reserve capacity. The available

[7]If the reserve reduction would not be possible, it can happen that curtailment of consumption occurs, even though there is sufficient production capacity available. However, in order to fulfil the given requirements, production is reduced in order to provide reserves and thus demand has to be rationed.

reserve capacity provided from a hydro power plant is the sum of all the reserve capacity provided from each linear piece ($p \in P_h$). The reserve capacity for upward regulation is defined as $(\overline{y}_p^{hp} - y_{p,\omega,\tau}^{hp^P})$ and $(y_{p,\omega,\tau}^{hp^P} - \underline{y}_p^{hp})$ for downward regulation. The minimum production capacity, defined as $\underline{y}_h^{hp}$, which normally is zero, can be negative to account for pumping capabilities of a hydro power plant.

$\forall p \in P,\ \omega \in W,\ \tau \in T$:

$$y_{p,\omega,\tau}^{hp^P} = y_{p,\omega,\tau}^{hp^*} + \Delta_{\uparrow} y_{p,\omega,\tau}^{hp^P} - \Delta_{\downarrow} y_{p,\omega,\tau}^{hp^P} \tag{5.12}$$

$$\underline{y}_{p,\omega,\tau}^{hp} \leq y_{p,\omega,\tau}^{hp^P} \leq \overline{y}_{p,\omega,\tau}^{hp} \tag{5.13}$$

$$0 \leq \Delta_{\uparrow} y_{p,\omega,\tau}^{hp^P}\ ,\ 0 \leq \Delta_{\downarrow} y_{p,\omega,\tau}^{hp^P} \tag{5.14}$$

Thermal power plants The redispatch constraint of thermal power plants is defined in equation 5.15. To include the minimum production level as well as start up and stop costs, the relative variables ($x_{g,\omega,\tau}^{th^P}$, $x_{g,\omega,\tau}^{\uparrow th^P}$, $x_{g,\omega,\tau}^{\downarrow th^P} \in [0,1]$) are introduced. $x_{g,\omega,\tau}^{th^P}$ represents the start up state of a thermal power plant. $x_{g,\omega,\tau}^{\uparrow th^P}$ and $x_{g,\omega,\tau}^{\downarrow th^P}$ describe the relative upward and downward reserve capacity available on each thermal power plant. Equations 5.16 to 5.17 define the production constraints of a thermal power plant and its start up constraint, similar to the methodology suggested by Warland et al. [101]. This definition allows a linear approximation of the unit-commitment optimisation for thermal power plants.

$\forall g \in G,\ \omega \in W,\ \tau \in T$:

$$y_{g,\omega,\tau}^{th^P} = y_{g,\omega,\tau}^{th^*} + \Delta_{\uparrow} y_{g,\omega,\tau}^{th^P} - \Delta_{\downarrow} y_{g,\omega,\tau}^{th^P} \tag{5.15}$$

$$y_{g,\omega,\tau}^{th^P} = \underline{y}_{g,\omega}^{th} \cdot x_{g,\omega,\tau}^{th^P} + x_{g,\omega,\tau}^{\downarrow th^P} \cdot \left(\overline{y}_{g,\omega}^{th} - \underline{y}_{g,\omega}^{th}\right) \tag{5.16}$$

$$x_{g,\omega,\tau}^{\uparrow th^P} + x_{g,\omega,\tau}^{\downarrow th^P} \leq x_{g,\omega,\tau}^{th^P} \tag{5.17}$$

$$0 \leq x_{g,\omega,\tau}^{\uparrow th^P}\ ,\ 0 \leq x_{g,\omega,\tau}^{\downarrow th^P}\ ,\ 0 \leq x_{g,\omega,\tau}^{th^P} \leq 1 \tag{5.18}$$

Equations 5.19 and 5.20 define the starting up of a thermal power plant ($z^{th^P}_{g,\omega,\tau}$) from one PTU ($\tau - 1$) to the next PTU τ, when its start up state $x^{th^P}_{g,\omega,\tau}$ changes. Equation 5.20 defines the optimization problem as a "round-coupled problem", i.e. thermal power plants which are started up at the beginning of a week ($\tau = 1$) are assumed to be started up at the end of the week ($\tau = max(T)$). The "round-coupling" is implemented to take into account the necessary start up of power plants with the begin of the new week, while having an independent optimisation problem for each week. Equations 5.19 and 5.20 result in the temporal connection between the PTUs. As only the starting up of a power plant is modelled explicitly, it is assumed that costs for stopping a thermal power plant are included in its start up costs. In the case of stopping a thermal power plant equation 5.21 defines that considered start up costs do not become negative.

$\forall g \in G,\ \omega \in W,\ \tau \in T/\{1\}$:

$$z^{th^P}_{g,\omega,\tau} \geq \left(x^{th^P}_{g,\omega,\tau} - x^{th^P}_{g,\omega,\tau-1}\right) \tag{5.19}$$

$\forall g \in G,\ \omega \in W$:

$$z^{th^P}_{g,\omega,\tau} \geq \left(x^{th^P}_{g,\omega,1} - x^{th^P}_{g,\omega,max(T)}\right) \tag{5.20}$$

$\forall g \in G,\ \omega \in W,\ \tau \in T$:

$$0 \leq z^{th^P}_{g,\omega,\tau} \tag{5.21}$$

In order to determine the reserve capacity, which is provided by a thermal power plant ($r^{\uparrow th}_{g,\omega,\tau}$ and $r^{\downarrow th}_{g,\omega,\tau}$), the relative values $x^{\uparrow th^P}_{g,\omega,\tau}$ and $x^{\downarrow th^P}_{g,\omega,\tau}$ have to be multiplied by the free dispatchable capacity of the power plant $\left(\overline{y}^{th}_{g,\omega} - \underline{y}^{th}_{g,\omega}\right)$, see equations 5.22 and 5.23.

$\forall g \in G,\ \omega \in W,\ \tau \in T$:

$$r^{\uparrow th}_{g,\omega,\tau} \leq x^{\uparrow th^P}_{g,\omega,\tau} \cdot \left(\overline{y}^{th}_{g,\omega} - \underline{y}^{th}_{g,\omega}\right) \tag{5.22}$$

$$r^{\downarrow th}_{g,\omega,\tau} \leq x^{\downarrow th^P}_{g,\omega,\tau} \cdot \left(\overline{y}^{th}_{g,\omega} - \underline{y}^{th}_{g,\omega}\right) \tag{5.23}$$

$$0 \leq r^{\uparrow th}_{g,\omega,\tau} \ , \ 0 \leq r^{\downarrow th}_{g,\omega,\tau} \tag{5.24}$$

In contrast to hydro power plants, thermal power plants, base-load power plants in particular, are subject to limited ramping. Thus, equations 5.25 and 5.26 reduce the reserve capacity, which can be provided by a thermal power plant to a certain percentage (s^{th}_g) of its production capacity. The maximum shares of reserves s^{th}_g for the different technologies used in the further analyses are stated in Table 5.3.

$\forall g \in G,\, \omega \in W,\, \tau \in T$:

$$r^{\uparrow th}_{g,\omega,\tau} \leq s^{th}_g \cdot \overline{y}^{th}_{g,\omega} \tag{5.25}$$

$$r^{\downarrow th}_{g,\omega,\tau} \leq s^{th}_g \cdot \overline{y}^{th}_{g,\omega} \tag{5.26}$$

Table 5.3: Available reserve capacity for different power plant types

Type	Nuclear	Lignite	Hard coal	Gas	Oil
Capacity available as reserve [%]	0	20	50	75	100

Generation load balance During the redispatch process, the balance between production and consumption has to be kept in each area, taking into account potential exchange. The balance constraint per area is defined in equation 5.27. It includes the redispatch of hydro and thermal power production, transmission, as well as the possible shut down and rationing in an area.

$\forall a \in A,\ \omega \in W,\ \tau \in T$:

$$\begin{aligned} 0 = &\sum_{g \in G_a} \left(y^{th^P}_{g,\omega,\tau} - y^{th^*}_{g,\omega,\tau} \right) + \sum_{h \in H_a} \sum_{p \in P_h} \left(y^{hp^P}_{p,\omega,\tau} - y^{hp^*}_{p,\omega,\tau} \right) \\ &+ \sum_{l \in L^f_a} \left(t^P_{l,\omega,\tau} - t^*_{l,\omega,\tau} \right) - \sum_{l \in L^t_a} \left(t^P_{l,\omega,\tau} - t^*_{l,\omega,\tau} \right) \\ &- \frac{1}{2} \sum_{l \in L^f_a \cup L^t_a} \left(d^P_{l,\omega,\tau} - d^*_{l,\omega,\tau} \right) + y^{rat^P}_{a,\omega,\tau} - y^{sh^P}_{a,\omega,\tau} \end{aligned} \tag{5.27}$$

Shut down and rationing Beside the possible redispatch of thermal as well as hydro power plants, a rationing of demand $y^{rat^P}_{a,\omega,\tau}$ and shut down of scheduled production $y^{sh^P}_{a,\omega,\tau}$ is possible. These are included in the balance equation 5.27, in order to keep the optimisation problem always feasible. Rationing can be compared to an anticipated curtailment of demand, in order to maintain the operational security during peak periods. Shut down of scheduled production, e.g. wind power production, nuclear or other base-load plants might be necessary during off-peak periods as well. $y^{rat^P}_{a,\omega,\tau}$ and $y^{sh^P}_{a,\omega,\tau}$ have to be positive, see equation 5.28.

$$0 \le y^{rat^P}_{a,\omega,\tau}\ ,\ 0 \le y^{sh^P}_{a,\omega,\tau} \tag{5.28}$$

Transmission Redispatching the exchange $t^P_{l,\omega,\tau}$ impacts transmission losses $d^P_{l,\omega,\tau}$, represented by equation 5.29. Furthermore, the transmission limits have to be taken into account, stated in equation 5.30 $\bar{t}_l$ and $\underline{t}_l$ represent the direction dependent NTCs of the according transmission lines.

$\forall l \in L,\ \omega \in W,\ \tau \in T$:

$$d^P_{l,\omega,\tau} \ge \left| t^P_{l,\omega,\tau} \cdot \alpha_l \right| \tag{5.29}$$

$$\underline{t}_l \le t^P_{l,\omega,\tau} \le \bar{t}_l \tag{5.30}$$

Cross-border procurement of reserve capacity In addition to the reserve capacity, which is available within the same control area, the exchange of reserve capacity is introduced by variables $e^{\uparrow}_{l,\omega,\tau}$ and $e^{\downarrow}_{l,\omega,\tau}$. To exchange reserve capacity, free capacity must be available on the relevant transmission lines, stated in Equations 5.31 and 5.32. This required transmission capacity is either freely available after the day-ahead spot market clearing or ise reserved on the transmission lines through redispatch. For the exchange of reserve capacity, the direction of the transmission lines has to be regarded, being either from (L^f_a) or to (L^t_a) an area a.

$\forall \tau \in T,\, \omega \in W,\, l \in L$:

$$\underline{t}_l \leq t^P_{l,\omega,\tau} + e^{\uparrow}_{l,\omega,\tau} \leq \bar{t}_l \tag{5.31}$$

$$\underline{t}_l \leq t^P_{l,\omega,\tau} - e^{\downarrow}_{l,\omega,\tau} \leq \bar{t}_l \tag{5.32}$$

To investigate different integration states of regulating power markets, equation 5.33 is introduced. L^P_x is the set of lines, on which a cross-border procurement of reserve capacity is allowed. Thus, on all other lines the exchange of reserve capacity is set to zero.

$\forall \tau \in T,\, \omega \in W,\, l \in L/L^P_x$:

$$e^{\uparrow}_{l,\omega,\tau} = 0\ ,\ e^{\downarrow}_{l,\omega,\tau} = 0 \tag{5.33}$$

Reserve procurement costs The objective for the optimisation problem is the minimisation of the total redispatch costs, which occur during the reserve procurement procedure. The objective function $C^P_\omega(.)$ is defined in equation 5.34.

$\forall \omega \in W$:

$$\begin{aligned}C^{P}_{\omega}(.) =& min\left(\sum_{\tau\in T}\left[\sum_{a\in A}\left(y^{rat^P}_{a,\omega,\tau}\cdot c^{rat^P} - y^{sh^P}_{a,\omega,\tau}\cdot c^{sh^P}\right)\right.\right.\\&+\sum_{g\in G}\left(\Delta_{\uparrow}y^{th^P}_{g,\omega,\tau}\cdot c^{\uparrow th^P}_{g,\omega,\tau} - \Delta_{\downarrow}y^{th^P}_{g,\omega,\tau}\cdot c^{\downarrow th^P}_{g,\omega,\tau}\right.\\&\quad\left.+\ z^{th^P}_{g,\omega,\tau}\cdot\ {}_{s}c^{th}_{g} + x^{th^P}_{g,\omega,\tau}\cdot\ {}_{f}c^{th}_{g}\right)\\&+\sum_{p\in P}\left(\Delta_{\uparrow}y^{hp^P}_{p,\omega,\tau}\cdot c^{\uparrow hp^P}_{p,\omega,\tau} - \Delta_{\downarrow}y^{hp^P}_{p,\omega,\tau}\cdot c^{\downarrow hp^P}_{p,\omega,\tau}\right)\\&\left.\left.+\ \sum_{k\in K} c^{red^P}\cdot\left(r^{\uparrow red}_{k,\omega,\tau} + r^{\downarrow red}_{k,\omega,\tau}\right)\right]\right)\\&-\sum_{\tau\in T}\sum_{g\in G}\left(z^{th^*}_{g,\omega,\tau}\cdot\ {}_{s}c^{th}_{g} + x^{th^*}_{g,\omega,\tau}\cdot\ {}_{f}c^{th}_{g}\right)\end{aligned} \tag{5.34}$$

The costs for the procurement of reserves includes the cost of redispatching, the cost of an additional start up of thermal power plants and the cost due to rationing and shut down. The calculation of procurement cost in Equation 5.34 consist of six parts, where only the first five parts are subject to the optimisation.

The first part represents the cost for rationing and shut down, which are assumed to happen at $c^{rat^P} = 3000$€/MWh and $c^{sh^P} = 0.03$€/MWh respectively. The value for rationing corresponds to the maximum bid price currently implemented by EEX European Energy Exchange AG [122]. Due to the formulation as a linear optimisation problem, the shut down of production has to receive an actual income slightly higher than 0€/MWh. The occurence of negative price, which can be seen occasionally in regulating power markets cannot be implement in the linear problem, but in a quadratic problem formulation[8].

The second, third and fourth part of the objective function represent the actual redispatch of power plants, i.e. the decrease of production on infra-marginal power plants and an increase on more expensive ones. The second and third part represent thermal power plants, including the costs for the upward and downward redispatch of power plants. In addition to the marginal redispatch costs,

[8] In the linear formulation of the problem, the transmission losses are solely described by a lower boundary, see Equation 5.29. If a cost for shut down would be defined in the linear formulation of the problem, the solver would increase the transmission losses instead of the production shut down, as there is no upper limit for the transmission losses. However, in the optimisation it is attained to determine the amount of production, which is necessary to be shut down, thus defining a small income for the shut down.

there are further costs due to the start up of thermal power plants ${}_{s}c^{th}_{g,\omega,\tau}$ and due to efficiency losses for thermal power plants, not running at full production.

Fig. 5.6 shows the example for a production cost curve of a thermal power plant. To that, its total production cost ${}_{T}c_g$ is plotted over its output y_g. The production cost increase of thermal power plants is assumed to be linear, resulting in constant marginal production costs ${}_{m}c_g$. However, as illustrated in Fig. 5.6, the linear approximation of the production cost does not cross the origin. This leaves the fixed cost ${}_{f}c_g$ for a thermal power plant, which is started up. This start up is indicated by $x^{th}_{g,\omega,\tau}$.

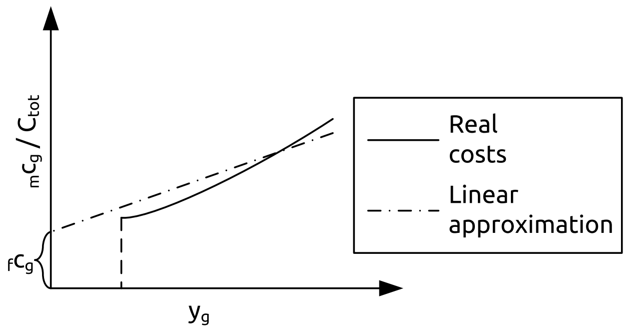


Figure 5.6: Definition of fixed and marginal production costs for thermal power plants

The fourth part of the objective function are costs due to redispatching hydro power production. These solely include marginal redispatch costs, as start and stop costs for hydro power plants are negligible. Efficiency losses of hydro power production are taken into account by the piece-wise linear cost functions of hydro power plants.

The fifth part of the objective function contains costs for rationing reserve capacity. The rationing is done at a fixed high cost of $c^{red} = 2500$€/MW. The cost indicates the violation of system operation rules resulting in a higher risk of operating the system.

The last part of the procurement costs is constant, representing the start up and fixed costs for thermal power plants, which are already scheduled due to the day-ahead market dispatch. The procurement costs should only include the additional start ups of thermal power plants due to reserve requirements, while the start up costs, already occurring during the day-ahead spot market clearing, are subtracted.

Marginal redispatch cost definition The marginal costs of redispatching a power plant are defined by equations 5.35 to 5.38. For the thermal power plants these marginal redispatch costs are based on the marginal production costs of the power plant and the area price. b^{th} represents the premium for rescheduling power plants and deviating from the optimal day-ahead dispatch. For thermal power plants b^{th} it is assumed to be approximately 1.025[9].

$\forall a \in A,\ g \in G_a,\ \omega \in W,\ \tau \in T$:

$$c^{\uparrow th^P}_{g,\omega,\tau} = max\left({}_m c^{th}_g \cdot b^{th^P}, \lambda_{a,\omega,\tau} \right) \tag{5.35}$$

$$c^{\downarrow th^P}_{g,\omega,\tau} = min\left({}_m c^{th}_g / b^{th^P}, \lambda_{a,\omega,\tau} \right) \tag{5.36}$$

For hydro power plants the marginal redispatch costs are based on the water value $v_{a,\omega}$ of the according reservoir, the marginal discharge value η_p for each linear piece p of a hydro power plant and the area price $\lambda_{a,\omega,\tau}$. The area price is regarded, to take into account constraints in the water courses. Due to minimum discharge constraints, hydro power plants might have to produce, even if it is not profitable (indicated by a production cost higher than the area price). In such a case, the marginal redispatch cost is set to the area price in order to prevent a re-optimisation of the day-ahead spot market dispatch. The premium for rescheduling is include as well, which is assumed to be 1.05 in the case of hydro power plants. The cost increase, represents an extra cost due to the deviation from the optimal production strategy of a hydro power plant. However, the impact on the reserve procurement is rather small, as hydro power production is redispatch seldom.

$\forall a \in A,\ h \in H_a,\ p \in P_h,\ \omega \in W,\ \tau \in T$:

$$c^{\uparrow hp^P}_{p,\omega,\tau} = max\left(\frac{v_{a,\omega}}{\eta_p} \cdot b^{hp^P}, \lambda_{a,\omega,\tau} \right) \tag{5.37}$$

$$c^{\downarrow hp^P}_{p,\omega,\tau} = min\left(\frac{v_{a,\omega}}{\eta_p} / b^{hp^P}, \lambda_{a,\omega,\tau} \right) \tag{5.38}$$

The constraints of the water course are not explicitly defined in the optimisation model. However, the occurrence of active constraints in the water course

[9]The increase in marginal costs is necessary as well, to prevent a re-optimisation of the day-ahead dispatch due to different optimisation models used for the day-ahead spot and the regulating power market.

can be observed in cases, when the production cost for a hydro plant is higher than the area price and it still is in production. In the case of such a active constraint the minimum $\underline{y}^{hp}_{p,\omega,\tau}$ and maximum $\overline{y}^{hp}_{p,\omega,\tau}$ production limits are set to the day-ahead production schedule $y^{hp^*}_{p,\omega,\tau}$. In order to fit the resulting reserve capacity available from hydro production, to actual values reported by Nordpool[10], the factors $\overline{y}^{hp^B}$ and $\underline{y}^{hp^B}$ are introduced.

$\forall a \in A,\ h \in H_a,\ p \in P_h,\ \omega \in W,\ \tau \in T$:

$$\begin{aligned} &\overline{y}^{hp}_{p,\omega,\tau} = min\left(\overline{y}^{hp}_{p}, y^{hp^*}_{p,\omega,\tau} + \overline{y}^{hp^B} \cdot \overline{y}^{hp}_{p,\omega,\tau}\right), if\ \lambda_{a,\omega,\tau} \geq v_{a,\omega} \cdot \eta_p \\ &\overline{y}^{hp}_{p,\omega,\tau} = \overline{y}^{hp}_{p}, otherwise \end{aligned} \tag{5.39}$$

$$\begin{aligned} &\underline{y}^{hp}_{p,\omega,\tau} = max\left(\underline{y}^{hp}_{p}, y^{hp^*}_{p,\omega,\tau} - \underline{y}^{hp^B} \cdot \overline{y}^{hp}_{p,\omega,\tau}\right), if\ \lambda_{a,\omega,\tau} \leq v_{a,\omega} \cdot \eta_p \\ &\underline{y}^{hp}_{p,\omega,\tau} = \underline{y}^{hp}_{p}, otherwise \end{aligned} \tag{5.40}$$

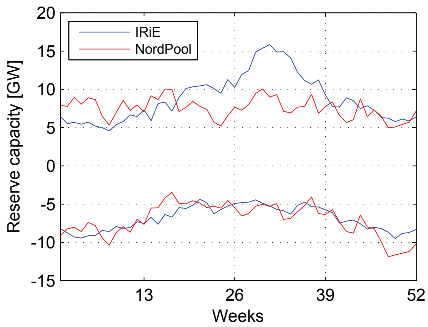


Figure 5.7: Average weekly availability of reserve capacity [GW] in Norway in 2010 NordPool vs. IRiE

Linear / Mixed-binary solution The reserve procurement procedure is executed for each separate week in a year. In order to achieve a meaningful result, the start up state of a thermal power plant needs to be defined as binary variables $x^{th^P}_{g,\omega,\tau} \in [0;1]$. However, with about 300 thermal power plants and the definition of 34 sequential periods throughout a week, this optimisation

[10]The comparison between the simulated available reserve capacity and actual values for Norway is shown in Fig. 5.7

problem would result in about 12000 binary variables per week. In order to reduce this number the problem is solved in two steps, solving an approximated linear problem and following a reduced mixed-binary problem. To obtain a linear problem the integrality of the optimisation problem is relaxed, i.e. the start up state of the thermal power plants $x_{g,\omega,\tau}^{th^P} \in [0;1]$ are defined as linear variables ($0 \leq x_{g,\omega,\tau}^{th^P} \leq 1$) and the optimisation problem is solved. In the second step all resulting definite start up states of thermal power plants ($x_{g,\omega,\tau}^{th^P} = 0 \vee x_{g,\omega,\tau}^{th^P} = 1$) are fixed to their values and only the remaining start up states ($0 < x_{g,\omega,\tau}^{th} < 1$) are defined as binary variables. This heuristic reduces the problem size to about 1500 binary variables per week. The reduction allows to solve the problem in a reasonable time.

5.1.3 System Balancing

After required reserve capacity is procured, it the system is balanced in real-time. As electricity cannot be stored to a large extent, production and consumption of electricity has to be kept in balance during real-time operation of the system. Balance is achieved through the activation of reserve capacity. The activation of reserve capacity corresponds to the acceptance of bids for balancing energy in the regulating power market. In order to achieve the best socio-economic outcome, these bids have to be activated in the order of their prices, taking into account remaining transmission capacity after the reserve procurement and transmission losses.

The system balancing is modelled as a linear optimisation problem. The notation for the following formulation of the model is to be found in appendix 5.6 of this chapter.

System imbalance

Inputs to the system balancing are the dispatch after the reserve procurement and results from the day-ahead spot market clearing, including area prices and water values. A further input are the imbalances of the system. The model's imbalances include the unplanned outages and load forecast error $\tilde{l}_{a,\omega,\tau}$ and the wind forecast error $\tilde{w}_{a,\omega,\tau}$. The former imbalances are represented by recorded imbalance scenarios of 2010 for the Netherlands, Belgium and Germany [23, 24, 106, 107, 108, 109], as well as recorded imbalance scenarios of 2010 for Norway, Sweden and Denmark [105]. As there is a difference between the PTU length in the RG CE and RGN, the imbalances of RGN are converted to a 15 minute resolution to achieve a matching PTU length. Recorded imbalances $\tilde{l}_{k,\omega,\tau}$ are only available for whole control areas. However, the system balancing model is based on the individual day-ahead areas to account for available transmission capacities. Thus, the imbalances are distributed by a share according to the ratio of the total annual consumption of an area ($cons_{a,\omega,\tau}$), see equation 5.41. This provides imbalance scenarios for all the individual areas.

$\forall k \in K,\ a \in A_k,\ \omega \in W,\ \tau \in T$:

$$\tilde{l}_{a,\omega,\tau} = \tilde{l}_{k,\omega,\tau} \cdot \frac{\sum_{\omega \in W, \tau \in T} cons_{a,\omega,\tau}}{\sum_{a \in A_k, \omega \in W, \tau \in T} cons_{a,\omega,\tau}} \tag{5.41}$$

In addition, imbalances due to the forecast error of wind power production $\tilde{w}_{k,\omega,\tau}$ are based on wind speed forecasts and installed wind production capacity, cf. Chapter 7.

System balancing model

Reserve activation The aim of the system balancing is to ensure that the supply equals the demand in the system within the given transmission limits for all PTUs. The power system balance constraint is defined for each area by equation 5.42. It includes the possible change in thermal power production, hydro power production, transmission with its according losses, rationing of demand and shut down of production. Whereas, thermal power production is divided into spinning and non-spinning reserves, as described in Section 5.1.2. The overall sum of reserve activation has to equal the imbalances in the according area, consisting of load and wind forecast errors as well as unplanned outages.

$\forall a \in A,\ \omega \in W,\ \tau \in T$:

$$\begin{aligned}
\tilde{l}_{a,\omega,\tau} + \tilde{w}_{a,\omega,\tau} = & \sum_{h \in H_a} \sum_{p \in P_h} \left(\Delta_{\uparrow} y^{hp^B}_{p,\omega,\tau} - \Delta_{\downarrow} y^{hp^B}_{p,\omega,\tau} \right) \\
& + \sum_{g \in G_a} \left(\Delta_{\uparrow} y^{th^B_s}_{g,\omega,\tau} - \Delta_{\downarrow} y^{th^B_s}_{g,\omega,\tau} + \Delta_{\uparrow} y^{th^B_n}_{g,\omega,\tau} - \Delta_{\downarrow} y^{th^B_n}_{g,\omega,\tau} \right) \\
& - \sum_{l \in L^f_a} \left(t^B_{l,\omega,\tau} - t^P_{l,\omega,\tau} \right) + \sum_{l \in L^t_a} \left(t^B_{l,\omega,\tau} - t^P_{l,\omega,\tau} \right) \\
& - \frac{1}{2} \sum_{l \in L^f_a \cup L^t_a} \left(d^B_{l,\omega,\tau} - d^P_{l,\omega,\tau} \right) \\
& + y^{rat^B}_{a,\omega,\tau} - y^{sh^B}_{a,\omega,\tau}
\end{aligned} \tag{5.42}$$

Transmission During system balancing the transmission dispatch can be changed, in order to exchange balancing energy. The constraint for real-time transmission $t^B_{l,\omega,\tau}$ within its limits is defined in equation 5.43 with the according transmission losses defined in equation 5.44. L^B_x represents the set of lines for which transmission is allowed to be changed during system balancing. This defines whether a line is available for the exchange of balancing energy or not, in order to study different levels of regulating power market integration.

$\forall l \in L,\ \omega \in W,\ \tau \in T$:

$$\underline{t_l} \leq t^B_{l,\omega,\tau} \leq \overline{t_l} \tag{5.43}$$

$$d^B_{l,\omega,\tau} \geq \left| t^B_{l,\omega,\tau} \cdot \alpha_l \right| \tag{5.44}$$

$\forall l \in L/L^B_x,\ \omega \in W,\ \tau \in T$:

$$t^B_{l,\omega,\tau} = t^P_{l,\omega,\tau} \tag{5.45}$$

Hydro power production The activated hydro reserve capacity is defined as $\Delta_{\uparrow} y^{hyd^B}_{h,\omega,\tau}$ and $\Delta_{\downarrow} y^{hyd^B}_{h,\omega,\tau}$, with the capacity constraints in equations 5.46 for upward regulation and 5.47 for downward regulation, respectively. The activation has to be positive and less or equal than the reserve capacity available from each linear piece of a hydro power plant.

$\forall p \in P,\ \omega \in W,\ \tau \in T$:

$$0 \leq \Delta_{\uparrow} y^{hp^B}_{p,\omega,\tau} \leq \overline{y}^{hp}_p - y^{hp^P}_{p,\omega,\tau} \tag{5.46}$$

$$0 \leq \Delta_{\downarrow} y^{hp^B}_{p,\omega,\tau} \leq y^{hp^P}_{p,\omega,\tau} - \underline{y}^{hp}_p \tag{5.47}$$

Thermal power production The limits for the activation of thermal reserve capacity are defined in equations 5.48 to 5.52. It is distinguished between spinning reserves ($\Delta_{\uparrow} y^{th^B_s}_{g,\omega,\tau}$, $\Delta_{\downarrow} y^{th^B_s}_{g,\omega,\tau}$) and non-spinning reserves ($\Delta_{\uparrow} y^{th^B_n}_{g,\omega,\tau}$, $\Delta_{\downarrow} y^{th^B_n}_{g,\omega,\tau}$). Spinning reserve capacity is made available after the reserve procurement, as shown in Fig. 5.3. Non-spinning reserve capacity combines further generation capacity of dispatchable thermal power plants, which are assumed to be able to start up or shut down in real-time. The non-spinning reserves are illustrated in Fig. 5.3 as well. Non-spinning reserves are included in the system balancing model to make dispatchable thermal generation capacity available for system balancing. The difference for the utilisation of spinning and non-spinning reserves is their activation cost, which is discussed further below.

$\forall g \in G,\, \omega \in W,\, \tau \in T$:

$$0 \leq \Delta_{\uparrow} y^{th^B_s}_{g,\omega,\tau} \leq r^{\uparrow th}_{g,\omega,\tau} \tag{5.48}$$

$$0 \leq \Delta_{\downarrow} y^{th^B_s}_{g,\omega,\tau} \leq r^{\downarrow th}_{g,\omega,\tau} \tag{5.49}$$

$$0 \leq \Delta_{\uparrow} y^{th^B_n}_{g,\omega,\tau} \ ,\ 0 \leq \Delta_{\downarrow} y^{th^B_n}_{g,\omega,\tau} \tag{5.50}$$

$$0 \leq y^{th^P}_{g,\omega,\tau} + \Delta_{\uparrow} y^{th^B_s}_{g,\omega,\tau} - \Delta_{\downarrow} y^{th^B_s}_{g,\omega,\tau} + \Delta_{\uparrow} y^{th^B_n}_{g,\omega,\tau} - \Delta_{\downarrow} y^{th^B_n}_{g,\omega,\tau} \leq \overline{y}^{th}_{g,\omega} \tag{5.51}$$

In addition to the limits implied by the capacity of the thermal power plants, equation 5.52, limits the total reserve activation to a certain percentage of the installed capacity of the power plant, as defined in the reserve procurement, see Table 5.3. Therefore, the total activated reserve capacity has to be lower or equal than the allowed share s^{th}_g.

$\forall g \in G,\, \omega \in W,\, \tau \in T$:

$$-s^{th}_g \cdot \overline{y}^{th}_{g,\omega} \leq \Delta_{\uparrow} y^{th^B_s}_{g,\omega,\tau} - \Delta_{\downarrow} y^{th^B_s}_{g,\omega,\tau} + \Delta_{\uparrow} y^{th^B_n}_{g,\omega,\tau} - \Delta_{\downarrow} y^{th^B_n}_{g,\omega,\tau} \leq s^{th}_g \cdot \overline{y}^{th}_{g,\omega} \tag{5.52}$$

Furthermore, G_n defines the set of thermal power plants, which can provide non-spinning reserves. These are assumed to be gas and oil-fired turbines. For all other power plants the activation of non-spinning reserves is prevented by equations 5.53.

$\forall g \in G/G_n,\, \omega \in W,\, \tau \in T$:

$$\Delta_{\uparrow} y^{th^B_n}_{g,\omega,\tau} = 0 \ ,\ \Delta_{\downarrow} y^{th^B_n}_{g,\omega,\tau} = 0 \tag{5.53}$$

System balancing costs The objective of the system balancing is to level out imbalances at minimum costs, through the activation of reserve capacity. The cost of system balancing is defined to be the cost of settling system imbalances by the activation of reserves instead of previous trading. This could be on the day-ahead spot or intra-day markets, which would be possible given a perfect forecast. The according objective function $C^B_{\omega,\tau}(.)$ is stated in equation 5.54. The linear problem is solved for each PTU τ individually as no temporal dependencies are defined, such as ramping or the start and stop constraints of power plants. In addition to the activation of reserve capacity, rationing of demand and shut down of production is included to ensure feasibility of the solution. These can be compared to the curtailment of consumption or the shut down of e.g. excess wind production during the real-time operation of the system.

$\forall \omega \in W,\, \tau \in T$:

$$\begin{aligned}
C^B_{\omega}\left(y^P\right) =& min \Bigg(\sum_{\tau \in T} \Bigg[\sum_{a \in A} \left(y^{rat^B}_{a,\omega,\tau} \cdot c^{rat^B} - y^{sh^B}_{a,\omega,\tau} \cdot c^{sh^B} \right) \\
& + \sum_{g \in G} \Big(\Delta_{\uparrow} y^{th^B_s}_{g,\omega,\tau} \cdot c^{\uparrow th^B_s}_{g,\omega,\tau} - \Delta_{\downarrow} y^{th^B_s}_{g,\omega,\tau} \cdot c^{\downarrow th^B_s}_{g,\omega,\tau} \\
& \quad + \Delta_{\uparrow} y^{th^B_n}_{g,\omega,\tau} \cdot c^{\uparrow th^B_n}_{g,\omega,\tau} - \Delta_{\downarrow} y^{th^B_n}_{g,\omega,\tau} \cdot c^{\downarrow th^B_n}_{g,\omega,\tau} \Big) \\
& + \sum_{p \in P} \left(\Delta_{\uparrow} y^{hp^B}_{p,\omega,\tau} \cdot c^{\uparrow hp^B}_{p,\omega,\tau} - \Delta_{\downarrow} y^{hp^B}_{p,\omega,\tau} \cdot c^{\downarrow hp^B}_{p,\omega,\tau} \right) \Bigg] \Bigg) \\
& - \sum_{\tau \in T} \sum_{a \in A} \lambda_{a,\omega,\tau} \cdot \left(\tilde{l}_{a,\omega,\tau} + \tilde{w}_{a,\omega,\tau} \right)
\end{aligned} \tag{5.54}$$

The last part of the objective function represents the potential cost or benefit of settling the imbalances at the day-ahead spot market price. The activation of regulating reserves always bears a cost to the society. Without accounting for the potential trade in the day-ahead market, the activation of downward regulating reserves, would actually indicate a benefit. However, settling the additional energy in one of the previous markets would lead to an increased benefit, as the cost of immediate actions can be avoided. These are included in the marginal reserve activation costs. As the intra-day market is not regarded in this model, it is assumed, that given a perfect forecast, the energy difference would have been traded in the day-ahead spot market.

Balancing cost definition In order to estimate the cost for the real-time system balancing, the marginal cost of balancing energy has to be determined.

As discussed in chapter 2, there are only a few researches done on the estimation and forecasting of regulating power prices, but none for the determination of marginal costs for balancing energy. The objective of the system balancing model is a socio-economic optimal activation of reserve capacity. Hence, the costs for balancing energy used in the presented model are based on the marginal production costs of the providing power plants. The determination of the costs of balancing energy are stated in equations 5.55 to 5.61. These are estimates roughly fitted to prices observed in current regulating power markets, cf. Jaehnert et al. [61]. For hydro power plants the reserve costs are based on the water value and the area price, including the premium of readiness b^{hp^B}, as described by Skytte [58]. This premium describes the additional costs of an immediate production change and the deviation from the optimal production schedule. The estimate is based on the fitting to observed prices in the Nordic regulating power market.

$\forall a \in A,\ h \in H_a,\ p \in P_h,\ \omega \in W,\ \tau \in T$:

$$c^{\uparrow hp^B}_{p,\omega,\tau} = max\left(\frac{v_{a,\omega}}{\eta_p} \cdot \Delta m_{h,\omega,\tau} \cdot b^{hp^B}, \lambda_{a,\omega,\tau}\right) \tag{5.55}$$

$$c^{\downarrow hp^B}_{p,\omega,\tau} = min\left(\frac{v_{a,\omega}}{\eta_p} \cdot \Delta m_{h,\omega,\tau} / b^{hp^B}, \lambda_{a,\omega,\tau}\right) \tag{5.56}$$

Activating reserve capacity results in a change of production and simultaneously affects the discharge of hydro power plants, hence the reservoir level. The water value of a reservoir is influenced by the change in the reservoir level. To avoid significant deviations from the optimal day-ahead dispatch schedule, the relative reservoir level deviation $\Delta m_{h,\omega,\tau}$ is tracked during each week. With the relative reservoir level deviation, the water value for each reservoir is updated after each hour of operation.

$\forall h \in H,\ \omega \in W,\ \tau \in T$:

$$\Delta m_{h,\omega,\tau} = 1 + \sum_{t=1..\tau} \sum_{p \in P_h} \left(\Delta_\uparrow y^{hp^B}_{p,\omega,\tau} - \Delta_\downarrow y^{hp^B}_{p,\omega,\tau}\right) / m_h \tag{5.57}$$

The marginal costs of balancing energy for spinning thermal power plants are based on their marginal production costs. In addition to the spinning, non-spinning reserves are defined. There are no start up or minimum production requirements defined for the non-spinning reserves. However, these are taken into account in the costs of the non-spinning reserves. The inclusion is done by adding or subtracting related start up costs to, respectively from, the marginal costs of balancing energy. This approach increases the costs quite substantially, which results in utilisation of non-spinning reserves in exceptional circumstances only.

$\forall a \in A,\ g \in G_a,\ \omega \in W,\ \tau \in T$:

$$c^{\uparrow th_s^B}_{g,\omega,\tau} = max\left(c^{th}_g \cdot b^{th^B}, \lambda_{a,\omega,\tau}\right) \tag{5.58}$$

$$c^{\downarrow th_s^B}_{g,\omega,\tau} = min\left(c^{th}_g / b^{th^B}, \lambda_{a,\omega,\tau}\right) \tag{5.59}$$

$$c^{\uparrow th_n^B}_{g,\omega,\tau} = max\left(c^{th}_g \cdot b^{th^B} + \frac{{}_s c^{th}_g}{\underline{y}^{th}_{g,\omega}}, \lambda_{a,\omega,\tau}\right) \tag{5.60}$$

$$c^{\downarrow th_n^B}_{g,\omega,\tau} = min\left(c^{th}_g / b^{th^B} - \frac{{}_s c^{th}_g}{\underline{y}^{th}_{g,\omega}}, \lambda_{a,\omega,\tau}\right) \tag{5.61}$$

Finally, rationing during system balancing is complicated, as it is not possible to drop the exact amount of demand. These situation additionally pose severe challenges to keep the system operational. This results in a much higher cost than for rationing during the day-ahead market clearing or reserve procurement. Thus, the cost of rationing during system balancing estimated to $c^{rat^B} = 10000$€/MWh, which is higher than any of the marginal costs for balancing energy. This value lies within the range of the Value of Lost Load determined by Frontier Economics [127] with 8 to 16 €/kWh, based on several international studies. The shut down cost of other than dispatchable production is set to $c^{sh^B} = 0.01$€/MWh during system balancing[11]

[11] Likewise for the reserve procurement, the shut down cost has to be set higher than zero as well, otherwise resulting in unreasonable results for transmission losses. See the description of shut down costs during reserve procurement above.

5.2 Case studies

A set of cases is defined, which represents a step-wise integration of the Northern European regulating power markets, distinguishing between the system-wide procurement of reserves and the system-wide activation of reserves.

In order to exchange balancing services between the Nordic system and continental Europe, free transmission capacity needs to be available after day-ahead spot market clearing on the HVDC-lines connecting RGN and RG CE. Fig. 5.2 shows percentiles of the total day-ahead exchange on these interconnections for the different inflow scenarios. The figure shows, that only during about 500h in the 0-percentile all lines are dispatched at their limit coevally in the same direction (import to the Nordic countries). Even during these hours an exchange of balancing services in one direction is possible, i.e. solely upward regulating reserves can be exported to continental Europe respectively downward regulating reserves exported to Nordic Europe. The remaining transmission capacity offers ample opportunities for the exchange of balancing services in Northern Europe.

As a basis for the case studies, a wet (1967), an average (1974) and a dry (1989) year are chosen as representative scenarios, referring to the inflow of the Nordic hydro system. Aggregate production and exchange of these years is stated in Table 5.4. There is a significant difference in the hydro power productions in these years. These differences have an impact on the overall operation of the power system, which is illustrated by the net energy exchange with continental Europe. The inflow situation in the Nordic countries impacts the thermal production in continental Europe, which is substantially higher in a dry year, as shown in the last row of Table 5.4. This results in potentially less available regulating reserves in the continental system during a dry year.

Table 5.4: Basis years for the analyses

	Wet	Average	Dry
Storable & non-storable inflow to Nordic hydro system (TWh)	249	194	146
Hydro production in Nordic system (TWh)	225	188	167
Annual net energy exchange from Nordel to UCTE (TWh)	20.6	6.3	-4.7
Thermal production in continental Europe (TWh)	792	805	817

For the case studies, different steps of regulating power market integration are defined. These steps reach from the state with no integration up to full integration of regulating power markets. Additionally a case with reserving transmission capacity for the regulating power market is included. The different cases are defined as follows:

Case I represents the state of the system before the integration of the German control areas / regulating power markets, cf. [64]. Regulating reserves have to be procured locally in each control area. Furthermore, there is no possibility to exchange balancing energy between Nordel and UCTE and no exchange possibility between UCTE's control areas. However, the energy exchange is possible between the control areas in Nordel.

Case II represents the state of the system after integrating the four German control areas as described in [43]. It is similar to Case I except that the exchange of reserve capacity and balancing energy is allowed between the German control areas.

Case III allows the cross-border procurement of 50% of the required regulating reserves for each control area and the system-wide exchange of balancing energy, representing a fully integrated European regulating power market.

Case IV includes a capacity reservation on the HVDC lines connecting Nordel and UCTE. Here 5% of the NTC is withdrawn from the day-ahead spot market and reserved exclusively for the regulating power market.

5.3 Results

The results of EMPS for a wet, an average and a dry year are taken as the basis for the further analysis with IRiE. A summary of the results from IRiE is shown in Table 5.5. The results are divided in the reserve procurement and system balancing. The exchange values presented in Table 5.5 refer to the HVDC lines between RGN and RG CE shown in Table 4.4.

5.3.1 Reserve procurement

In general, a higher level of integration results in less redispatch because of increased flexibility. The integration of the German areas results in a redispatch reduction of about 20%. The system-wide exchange of reserve capacity causes a further significant reduction by about 40% of the necessary redispatch. This is due to an increasing procurement of reserves in the Nordic area, where upward reserve capacity constitute the highest share. The average upward respectively downward exchange of reserve capacity in Table 5.5 is the sum of exchange in both directions. However, the procurement of reserves is almost only done corss border from RGN to RG CE. The cross-border reserve procurement for the average year is depicted in Fig. 5.8. The maximum export of reserve capacity from Nordel is about 2000MW, which complies with the maximum allowed share of 50% of the reserve requirements in the continental countries in the model (4070MW). During the summer time a slight dip in the exchange of reserves can be seen, which is due to already nearly full export in the day-ahead dispatch.

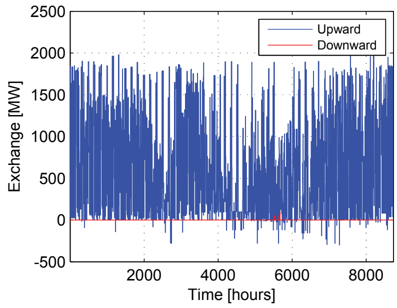


Figure 5.8: Exchange of reserve capacity from Nordel to UCTE for case III in the average year

The average procurement of upward reserves in the average year per country is shown in Fig. 5.9. The Nordic countries Norway and Sweden are the exporters, whilst Denmark and Germany are importing reserve capacity. The high export of reserves from Sweden compared to Norway has two reasons. Firstly internal congestions are not regarded in 2010, thus an export of reserves, which are located in northern Sweden occurs. Secondly Sweden has a higher interconnection capacity to continental Europe. Denmark imports nearly 50% of its required reserve (1200MW), which corresponds to the maximum allowed share. Analyses show, that with a relaxation of this maximum allowed share the import would increase even further.

Case IV with the additional reservation of transmission capacity for the regulating power market results in a further increase of the cross-border procurement of reserves, due, more available transmission capacity. However, the only minor increase of exchange shows that there already is ample transmission capacity available without a reservation.

There is a potential for large savings due to exchange of reserve capacity

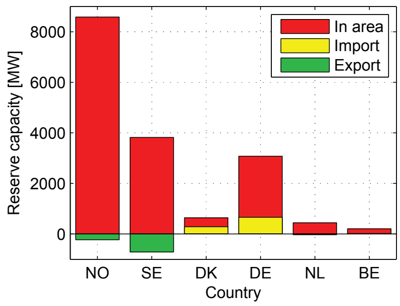


Figure 5.9: Average available reserve capacity and reserve capacity exchange in the countries for case III in the average year

between countries. The benefit resulting from the integration of the German areas is about 15 million Euro per annum, somewhat less than estimated in [43]. This difference is caused by the difference between the present procurement regimes in Germany and the approach used in the model. The integrated reserve procurement and day-market clearing results in a better dispatch than the present practices in Germany, reducing the potential for savings. Still the total savings resulting from system-wide exchange of reserve capacity are about 30%, or between 40 to 50 million Euro per annum. These savings show that there is a huge opportunity for Nordel to provide reserve capcity to the UCTE.

5.3.2 System balancing

The right part of Table 5.5 shows the results for the system balancing. There is also a significant reduction of the reserve activation resulting from the integration of regulating power markets. Already the integration of the German areas results in a reduction of about 40% in RG CE. A system-wide exchange of balancing energy brings a further reduction of about 55% of reserve activation in the RG CE. At the same time there are only slight changes of reserve activation in RGN. This results in a net reduction of reserve activation of about 40%, caused by the netting of the imbalances in different countries.

In the case of a system-wide exchange, the annual gross balancing energy exchange is about 4000MWh. The net exchange is smaller compared to the gross exchange, showing that there is no significant total energy export. Hence, there is an export of generation flexibility. This is also illustrated in Fig. 5.10, where the balancing energy exchange for case III in the average year is shown. The exchange seem to be equally distributed in both directions.

The last two columns in Table 5.5 show the shut down of fixed production

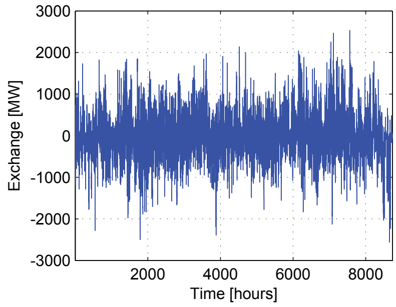


Figure 5.10: Exchange of regulating energy from Nordel to the UCTE for case III in the average year

and the rationing of demand during system balancing. Shut down and rationing are applied during hours, when there are not sufficient reserves available in an area. It can be seen, that there is a reduction of rationing and shut down due to the integration of regulating power markets. This decrease indicates a higher availability of regulating reserves and hence an increase in system security.

The results show that an integrated balancing of the system results in a significant reduction of the system balancing costs. The integration of the German markets has a benefit of about 180 million Euro per annum, what is comparable to estimates in [43]. The system-wide integration and an additional reservation of transmission capacity lead to further reductions of about 90 and about 10 million Euro per annum respectively. The main savings are due to the reduction of reserve activation in RG CE. With the ability of a system-wide exchange of balancing energy, the activation of reserves in RGN only changes by a smaller amount. Hence, there is no significant substitution of continental activation of thermal reserves by Nordic hydro reserves, but a netting of imbalances, resulting in decreased continental reserve activation.

Case IV with the reservation of transmission capacity leads to an additional benefit of about 20 million Euro in total. This benefit is due to the increasing exchange possibilities in the regulating power market, assuming that the reserved capacity was withdrawn from the day-ahead spot-market.

Table 5.5: Annual reserve procurement and system balancing results in a dry, an average and a wet year

		Reserve procurement				System balancing						
			Average exchange				Reserve activation		Exchange			
Year	Case	Cost M€	upward MW	downward MW	Redispatch GWh	Cost M€	RG CE GWh	RGN GWh	gross GWh	net GWh	Shut down GWh	Rationing GWh
dry	I	168	0	0	6177	393	11584	4712	0	0	37	318
	II	153	0	0	5547	205	7114	4713	0	0	0	36
	III	101	981	0	4104	109	3529	4607	3976	-523	0	6.0
	IV	99	1019	0	4045	103	3328	4615	4812	-658	0	5.1
avg	I	166	0	0	6433	375	11584	4635	0	0	39	311
	II	153	0	0	5906	191	7179	4637	0	0	0	37
	III	113	737	0	4570	97	3138	5003	4609	-1205	0	3.2
	IV	110	788	0	4492	92	2906	5035	5326	-1104	0	2.9
wet	I	161	0	0	5930	369	11584	4873	0	0	35	309
	II	148	0	0	5386	194	7311	4870	0	0	0	32
	III	111	552	3	4148	106	3388	5233	4179	-1171	0	1.2
	IV	108	611	3	4034	97	3162	5168	5177	-937	0	2.5

5.4 Discussion

The IRiE model is developed specifically for the purpose of simulating regulating power markets and their integration. Thus, the validity of its results needs to be commented. Firstly the costs for procurement and for the activation of regulating reserves are estimates based on the marginal production costs of thermal power plants and based on the water values for hydro power plants. These costs are not necessarily reflected by prices which are observed in today's regulating power markets. The implicit perfect market assumptions potentially underestimates costs occurring in regulating power markets. Moreover, as the regulating power market integration leads to increased competition, the model rather under- than overestimates the benefit of the market integration.

Secondly, the procurement of reserves is executed after the day-ahead system dispatch is known. As shown by [128], this sequence of the day-ahead spot market and the reserve procurement dispenses with the trade-off between providing reserve capacity and bidding in the day-ahead spot market. Hence, reserve prices are often zero. Due to the approach, the resulting simulated reserve procurement costs are a lower limit or the actual socio-economic costs for having the required reserves available in the system.

Finally, while the actual socio-economic outcome is an approximation of a complex reality, the underlying changes in the operation of the regulating power market clearly indicate the potential benefits. On the one hand the procurement of regulating reserves in the Nordic area, significantly reduces the need for redispatch and therefore reduces procurement costs in the continental system. On the other hand the significant reduction of reserve activation due to a system-wide netting of imbalance reduces the cost of system balancing.

5.5 Conclusion

The model for an integrated Northern European regulating power market is presented, which is based on a common Northern European day-ahead spot market clearing. It arises that the Nordic power system has ample regulating reserves at its disposal, due to the good regulating capability of the hydro power production. Moreover, after the clearing of the day-ahead spot market, mostly free transmission capacity remains, leaving the possibility for further exchange.

With the potential integration of national regulating power markets parts of the required continental regulating reserves can be procured in the Nordic system and balancing energy can be exchanged system-wide. For this exchange of balancing services the available transmission capacity after the day-ahead spot market clearing has to be taken into account.

With a set of different cases, a stepwise integration of the Northern European regulating power markets is studied. The comparison with the recent integration of the German regulating markets shows comparable results in the case of system balancing. A system-wide regulating reserve procurement, reduces the necessary redispatch by 40%. On average 20% of reserves required for the RG CE are procured in RGN. The activation of regulating reserves can be reduced by 40% due to system-wide netting of imbalances, which is comparable to results presented by Vandezande [21]. Here, the reserve acitvation is reduced to 22%, being somewhat less, which is certainly due the consideration of only two countries.

Summarising, savings can be achieved mainly due to the procurement of reserves in the Nordic area and the netting of imbalances of different countries.

5.6 Appendix

The notation used throughout the description of the regulating power market model is stated below.

Indicators

$*$	Day-ahead market
P	Resource procurement
B	System balancing
$\uparrow$ / $\downarrow$	Upward / downward
$^{-}$ / $_{-}$	Maximum / minimum

Sets and indices

$a \in A$	Day-ahead areas defined in EMPS
$k \in K$	Control areas
$h \in H$	Hydro plants with H_a, H_k being subsets of hydro plants situated in areas a or k respectively
$p \in P$	Linear pieces of all hydro power plants with P_h being the subset of linear pieces of one hydro power plant h
$g \in G$	Thermal plants with G_a, G_k being subsets of thermal plants situated in areas a or k respectively
$l \in L$	Transmission lines with L_a^t, L_a^f being subsets of lines transmitting to and from the an area a and L_x^P, L_x^B being the sets of lines across which reserves are procured and activated
$\omega \in W$	Weeks
$\tau \in T$	PTUs (quarter hours) during a week

Objective functions

$C_\omega^P(.)$	Cost function of reserve procurement
$C_{\omega,\tau}^B(.)$	Cost function of system balancing

Water values and area prices

Parameter:

$v_{a,\omega}$, $\lambda_{a,\omega}$	Water value and day-ahead spot price in each area

Hydro generation

Parameter:

$y^{hp^*}_{p,\omega,\tau}$	Day-ahead dispatch of hydro plant pieces
$\overline{y}^{hp}_{p,\omega,\tau}$, $\underline{y}^{hp}_{p,\omega,\tau}$	Maximum and minimum production of hydro plants
η_p	Marginal efficiency for a linear piece of a hydro plant
$c^{\uparrow hp^P}_{p,\omega,\tau}$, $c^{\downarrow hp^P}_{p,\omega,\tau}$	Marginal redispatch cost of hydro plant pieces
$c^{\uparrow hp^B}_{p,\omega,\tau}$, $c^{\downarrow hp^B}_{p,\omega,\tau}$	Marginal up- and downward regulating cost of hydro plant pieces
m_h	Reservoir content

Variables:

$y^{hp^P}_{p,\omega,\tau}$	Dispatch of hydro plant pieces after reserve procurement
$\Delta_\uparrow y^{hp^P}_{p,\omega,\tau}$, $\Delta_\downarrow y^{hp^P}_{p,\omega,\tau}$	Redispatch of hydro plant pieces during reserve procurement
$\Delta_\uparrow y^{hp^B}_{p,\omega,\tau}$, $\Delta_\downarrow y^{hp^B}_{p,\omega,\tau}$	Up- and downward regulating of hydro plant pieces during system balancing

Thermal generation

Parameter:

$y^{th^*}_{g,\omega,\tau}$	Day-ahead dispatch of thermal plants
$\overline{y}^{th}_{g,\omega}$, $\underline{y}^{th}_{g,\omega}$	Maximum and minimum generation capacity of thermal plants
$x^{th^*}_{g,\omega,\tau}$	Start up state of thermal plants at day-ahead spot
$z^{th^*}_{g,\omega,\tau}$	Starting up of thermal plants per time unit at day-ahead spot

s_g^{th}	Share of thermal power plant capacity available as reserves
${}_mc_g^{th}$	Marginal cost cost of thermal plants
${}_sc_g^{th}$	Start up cost of thermal plants
${}_fc_g^{th}$	Fixed cost of thermal plants
$c_{g,\omega,\tau}^{\uparrow th^P}$, $c_{g,\omega,\tau}^{\downarrow th^P}$	Marginal redispatch cost thermal plants in reserve procurement
$c_{g,\omega,\tau}^{\uparrow th_s^B}$, $c_{g,\omega,\tau}^{\downarrow th_s^B}$	Marginal up- and downward regulating cost of thermal plants for spinning reserve
$c_{g,\omega,\tau}^{\uparrow th_n^B}$, $c_{g,\omega,\tau}^{\downarrow th_n^B}$	Marginal up- and downward regulating cost of thermal plants for non-spinning reserve

Variables:

$y_{g,\omega,\tau}^{th^P}$	Dispatch of thermal plants after reserve procurement
$\Delta_\uparrow y_{g,\omega,\tau}^{th^P}$, $\Delta_\downarrow y_{g,\omega,\tau}^{th^P}$	Redispatch of thermal plants during reserve procurement
$\Delta_\uparrow y_{g,\omega,\tau}^{th_s^B}$, $\Delta_\downarrow y_{g,\omega,\tau}^{th_s^B}$	Spinning up- and downward regulating of thermal plants during system balancing
$\Delta_\uparrow y_{g,\omega,\tau}^{th_n^B}$, $\Delta_\downarrow y_{g,\omega,\tau}^{th_n^B}$	Non-spinning up- and downward regulating of thermal plants during system balancing
$x_{g,\omega,\tau}^{th^P}$	Start up state of thermal plants after reserve procurement
$z_{g,\omega,\tau}^{th^P}$	Starting up of thermal plants per time unit after reserve procurement
$x_{g,\omega,\tau}^{\uparrow th^P}$, $x_{g,\omega,\tau}^{\downarrow th^P}$	Up- and downward reserve provision of thermal plants
$r_{g,\omega,\tau}^{\uparrow th}$, $r_{g,\omega,\tau}^{\downarrow th}$	Up- and downward reserves provided by a thermal plant

Transmission lines

Parameter:	
$t^*_{l,\omega,\tau}$	Transmission dispatch after day-ahead spot market clearing
$\bar{t}_l$, $\underline{t}_l$	Maximum and minimum transmission limits
α_l	Linear losses of transmission lines
Variables:	
$t^P_{l,\omega,\tau}$, $t^B_{l,\omega,\tau}$	Transmission dispatch after reserve procurement and during system balancing
$d^*_{l,\omega,\tau}$, $d^P_{l,\omega,\tau}$, $d^B_{l,\omega,\tau}$	Transmission losses for day-ahead dispatch, after reserve procurement and during system balancing
$e^{\uparrow}_{l,\omega,\tau}$, $e^{\downarrow}_{l,\omega,\tau}$	Reserve procurement across transmission lines

Rationing and shut down

Parameter:	
c^{rat^P}, c^{rat^B}	Cost of rationing
c^{sh^P}, c^{sh^B}	Cost of shut down
Variables:	
$y^{rat^P}_{a,\omega,\tau}$, $y^{rat^B}_{a,\omega,\tau}$	Rationing during reserve procurement and in system balancing
$y^{sh^P}_{a,\omega,\tau}$, $y^{sh^B}_{a,\omega,\tau}$	Generation shut down during reserve procurement and system balancing

Reserve requirements

Parameter:

$r_k^{\uparrow r}$, $r_k^{\downarrow r}$	Up- and downward reserve requirements in each control area
$r^{\uparrow r}$, $r^{\downarrow r}$	Up- and downward reserve requirements in the total system
s^r	Share of reserves, which needs to be procured in the own control area
c^{red}	Cost of reserve reduction

Variables:

$r_{a,\omega,\tau}^{\uparrow}$, $r_{a,\omega,\tau}^{\uparrow}$	Up- and downward reserves available in a control area
$r_{k,\omega,\tau}^{\uparrow red}$, $r_{k,\omega,\tau}^{\downarrow red}$	Reduction of up- and downward reserve requirements

System imbalances

Parameter:

$\tilde{l}_{a,\omega,\tau}$	Load forecast in each area
$\tilde{w}_{a,\omega,\tau}$	Wind forecast error in each area

Part II

Analyses

Succending the establishment of the regulating power market model, a set of specific analyses is performed. These analyses are presented in the second part of the thesis. The investigation mainly concerns the expected cost increase in the regulating power market and the potential benefit of integrating national regulating power markets. The scope of the analyses in Northern Europe, where a socio-economic view is taken.

The following chapters contain **Publication D** to **Publication G** in chronological order. All analyses are updated with results of the latest and updated simulations, which however do not change the main conclusions of the publications.

The analyses include the issue of a transmission capacity reservation to the exclusive utilisation in the regulating power market, which is presented in Chapter 6. The second analysis assesses the integration of large amounts of wind power production capacity in the Northern European power system and resulting challenges for the system balancing, presented in Chapter 7. The last analysis, presented in Chapter 8, addresses various wind power production forecast horizons as well as different reserve requirement levels and their impact on the outcome of the regulating power markets.

Chapter 6

Transmission capacity reservation

The investigation of reserving transmission capacity on HVDC lines exclusively for the exchange in the regulating power market is investigated in **Publication D** and presented hereafter. The publication is called "Reservation of transmission capacity for the exchange of regulating resources in Northern Europe: Is there a benefit?" Sections 4 and 5 of the publication are included as succeeding Section 6.2 and 6.3, with minor editorial changes.

6.1 Analysis introduction

In order to exchange regulating reserves, a reservation of transmission capacity on certain interconnections might be beneficial. Studies done by Abbasy et al. [78] and Frontier Economics [77], which are done on a simplified level based on a statistical analysis, show a benefit of reserving transmission capacity. However, the withdrawal of transmission capacity from the day-ahead spot market is not taken into account by Abbasy et al. [78]. Frontier Economics [77] likewise utilize time-series of imbalances and regulating power prices, neglecting impacts on prices in the countries.

Beside the studies, in reality a capacity of 100MW is planned to be reserved for the exchange of regulating resources on the new Skagerrak 4 cable, connecting Norway and Denmark [53].

6.2 Case studies

In order to answer the question raised, several cases are studied. As a basis for the study the previously described models are used, representing the 2010's state of the power system. The presented analysis is made for an average year with respect to the inflow to the Nordic hydro system, which in this case is 192 TWh per annum.

The studied cases differ in the available transmission capacity for the day-ahead spot market. A capacity reservation is done on HVDC lines connecting the Nordic countries and continental Europe, cf. Table 4.1. In the first case the full transmission capacity is offered to the day-ahead spot market. After the day-ahead spot market clearing, the remaining transmission capacity can be used for trading in the regulating power market. For the further two studied cases the transmission capacity offered to the day-ahead spot market on the previously mentioned HVDC lines is decreased by 5% and 10% respectively in order to reserve this capacity for the exchange of regulating reserves. The reservation is done for the exchange of up- as well as downward regulating reserves. In these cases the remaining transmission capacity after day-ahead spot market clearing plus the reserved capacity is offered to the regulating power market, including the reserve procurement and the system balancing.

6.3 Results

The results of the case studies for reserving transmission capacity are shown in Table 6.1 for the day-ahead market outcome and in Table 6.2 for the regulating power market outcome. Results for the cases of full capacity available to the day-ahead spot market, a 5% and a 10% reservation capacity are shown in the subsequent tables. In addition the case of no integration of the Northern European regulating power markets, as discussed in chapter 5, is shown as a comparison to classify the transmission reservation outcomes.

Table 6.1 shows that the reservation of transmission capacity and thus withdrawal of trading possibilities from the day-ahead market has a strong impact on the outcome of the day-ahead spot market clearing. The reservation of transmission capacity for balancing reduces the socio-economic benefit by decreasing the dispatched exchange of electricity between the Nordic area and continental Europe, by about 4% and 8%. However, the outcomes are quite different for the various market participants. A distinction must be made between Nordic and continental European participants, as there is a day-ahead spot price decrease in the Nordic countries and increase in the continental countries. Due to these price changes, there is a benefit for continental producers and a loss for continental consumers. In the Nordic area the outcome is the opposite, with large losses for the Nordic producers. For the TSOs[1] the reduction of available transmission capacity on the day-ahead spot market is slightly beneficial. Looking on the individual transmission lines on which capacity is reserved, it shows that there are different outcomes too. A benefit can be seen on the Skagerrak cable. For the Kontek and the Baltic cable there is no change, whereas on the NorNed cable a loss can be seen. An explanation for benefit for the TSOs of reserving transmission capacity can be that the reservation brings the available transmission capacity to the day-ahead market closer to the optimal transmission capacity for a TSO. The income to the TSOs is the Congestion capacity cost, as defined in [129]. This income for the TSO is maximized if the available transmission capacity is 50% of the transmission capacity which is necessary in order not to have congestions on the transmission line.

Table 6.1: Day-ahead market outcome of reserving transmission capacity

	No integration	Full integration	5% reservation	10% reservation
Socio-economic outcome [M€]	-	-	-79.5	-260
Gross exchange [TWh]	17.4	17.4	16.8	16.3
TSO outcome [k€]	-	-	38.0	226
RGN producer outcome [M€]	-	-	-82.1	-277
RGN consumer outcome [M€]	-	-	17.3	37.4
RG CE producer outcome [M€]	-	-	7.5	29.6
RG CE consumer outcome [M€]	-	-	-19.7	-44.5

The case study shows that there is no linear change of the economic outcome with the amount of capacity reservation. With a 10% reservation of transmission capacity for the exchange of regulating resources there is a significant higher decrease of the socio-economic benefit, as well as losses for the Nordic producers and benefits for the continental producers compared with the 5% reservation.

Table 6.2 shows the outcome on the regulating power market due to the reservation of transmission capacity. The table shows the outcomes for the reserve procurement as well as the system balancing. By the transmission reservation the reserve procurement costs are reduced by 3% and 6% respectively, but compared to the process of integrating the markets this is only a minor benefit. The increase in the externally procured reserves is also only marginal, resulting in a minor reduction of the necessary redispatch during the reserve procurement.

[1]TSOs are assumed to be the owner of the HVDC lines in this analysis and thus the profiting companies.

An explanation for it can be that normally there is already enough free capacity available after the day-ahead spot market clearing. In the hours where this is not the case the reservation of 5% or 10% of transmission capacity is not enough to increase the procurable reserves significantly.

The balance settlement costs are reduced by about 10% and 15% respectively by the additional available transmission capacity for the exchange of balancing energy. The reservation of capacity for balancing reduces the total activated reserves slightly by an increased netting of imbalances. The gross exchange of balancing energy between the Nordic and the continental European countries increases significantly by 15% and 30%. The increase in the exchange of balancing energy results in an additional benefit for the TSOs, which is four times as high in the case of reserving 10% of transmission capacity for the exchange of balancing energy.

Table 6.2: Day-ahead market outcome of reserving transmission capacity

	No integration	Full integration	5% reservation	10% reservation
Reserve procurement costs [M€]	153	113	110	107
Average reserves procured from RGN to RG CE [GW]	0	737	788	831
Redispatch [GWh]	5906	4570	4492	4419
Balance settlement costs [M€]	196	105	95.6	91.1
Gross activated reserves [GWh]	12310	8585	8382	8224
Gross exchange [GWh]	0	4635	5378	6072
TSO income [M€]	0	3.3	8.6	12.0

Combining the outcome of the day-ahead spot market and the regulating power market shows that there is a benefit for the TSOs to reserve transmission capacity for the exchange of regulating reserves. As the transmission lines are operated by the TSOs, they have an incentive for the reservation of transmission capacity, although this would reduce the socio-economic benefit significantly.

Fig. 6.1 depicts the duration curve of the aggregated real-time exchange on the lines connecting the Nordic and the continental European area. It shows that the resulting utilisation of the interconnections is quite similar in all cases. Almost never all of the lines are used at their maximum capacity at the same time.

In Fig. 6.2 the duration curve for the exchange of balancing energy is shown for the different cases studied. In the case of no integration there is by definition

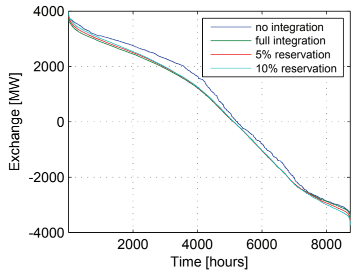


Figure 6.1: Duration curves of real-time exchange between Nordic and continental European countries

no exchange of balancing energy. There is only a small difference between the case of full integration and the case of additional reservation of 10% of transmission capacity. The increased exchange is mainly during the hours, where there is only little exchange of balancing energy, which probably results from additional netting of imbalances. This also results in less activation of regulating reserves in the continental countries as will be discussed subsequently.

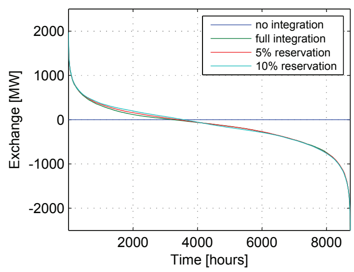
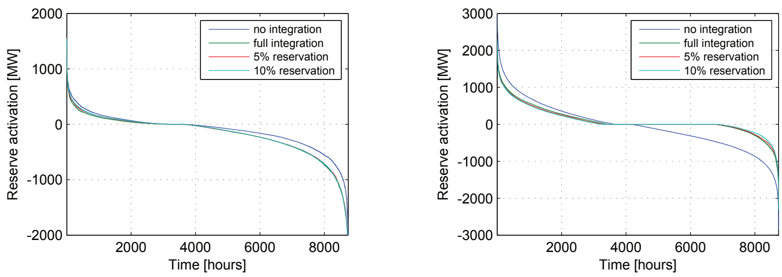


Figure 6.2: Duration curve of real-time exchange of balancing energy between Nordic and continental European countries

The reserve activation in Norway (Fig. 6.3a) and Germany (Fig. 6.3b) is shown in duration curves below. For Norway there is an increase in the activation of the reserves with the integration of regulating power markets, whereas the increase due to the reservation of transmission capacity is only marginal. For Germany the impact is the opposite. There is a significant reduction of reserve activation coming with the integration of the regulating power markets. The reservation of transmission capacity for the exchange of regulating reserves reduces such activation even more. Furthermore, due to the exchange of balancing energy there are about 3000 hours of the year without activation of reserves in this area, which are even more in the case of capacity reservation. The increase of the time, where there is no activation of regulating reserves is due to the netting of imbalances and the activation of cheaper hydro reserves situated in the Nordic countries instead of the thermal ones in the continental countries.

The decrease of reserve activation results in a significant decrease of the expected income for participants bidding in the regulating power market in continental Europe. As regulating reserves are activated only in a few hours during a year, it becomes much more improbable for regulating power market participants to get their bids for balancing energy accepted. Thus, it becomes much harder to recover fixed costs on the plants, which are used for the provision of regulating reserves by the sale of balancing energy. The procurement of regulating reserves with a capacity payment for providing reserves becomes more important in this case. This payment can be used to recover the fixed cost of the power plants.



(a) Norway (b) Germany

Figure 6.3: Regulating reserve activation in Germany (transpower area)

In addition to the reduction of activated reserves also the maximum activated upward reserves are reduced by about 200MW, whereat the maximum activated downward reserves are increased by about 300MW. This shows that a reduction of the reserve requirements in this control area would be possible.

6.4 Discussion

The results of the analysis have to been seen within the context of the model. As described previously the regulating power market incorporates a market sequence, where first the day-ahead market is clearly and succeedingly reserves are procured, being the opposite to the market sequences currently implemented in Europe. Additionally, reserve capacity for secondary control is often contracted for a longer period, as stated in Tab. 2.3, where in the model it is only contracted for one hour. Thus, the model results in a better dispatch than can be expected in the real markets. This results in less benefits in the regulating power market, by the availability of increased transmission capacity.

The reservation level analysed here are 5% and 10% of the total transmission capacity between the Nordic are and continental Europe, showing a non-linear increase of the losses in the day-ahead spot market. However, as part of the application for the Skagerrak 4 cable only 100 MW are intended to be reserved for the utilisation in the regulating power market [53]. This can be seen as a marginal reservation of transmission capacity, potentially being profitable for the society.

The analysis shows, that withdrawing a part of the transmission capacity from the day-ahead market leads to significant socio-economic losses, which need to be taken into account. These losses are mainly observed for power producers in the Nordic area. The analysis also illustrates, that cable owners, here assumed to be the TSOs are profiting from the reservation, in the day-ahead spot market as well as the regulating power market. Thus, also supervision of TSO by regulators is necessary, in order to achieve the socio-economic optimal outcome.

The main result of the analysis is, that an integration of national regulating power market is socio-economically beneficial. The reservation of transmission capacity for the exclusive utilisation in the regulating power market, leads to a further cost reduction, but has to be valued against the losses in the day-ahead spot market. In the case study presented in this paper, the overall socio-economic outcome of the transmission reservation is negative.

6.5 Conclusion

The outcome of reserving transmission capacity exclusively to the exchange of balancing services in Northern European area is assessed. For that, two cases with a reservation of 5% and 10% of the total transmission capacity are simulated and compared to a third case without a reservation of transmission capacity. The day-ahead market and regulating power market outcome is calculated for all of the cases.

The simulations show that the reservation of transmission capacity increases the exchange of balancing services significantly. This likewise implies a significant reduction of reserve procurement and system balancing costs. However, the resulting cost reduction in the regulating power market is far lower than the decrease in the socio-economic benefit, which is observed in the day-ahead market.

Considering different participants in the day-ahead market it turns out that the outcome of a transmission reservation is different for producers, consumers and the TSOs, which are assumed to be the cable owner. Especially for the TSOs there is a benefit of reserving transmission capacity in both the day-ahead market and the regulating power market. Hence, the analysis points out that it would be profitable for them to implement such a capacity reservation. This calls for an active role of the regulators in order to achieve the best socio-economic outcome.

A marginal reservation of transmission capacity as suggested by [53] might be beneficial. But in this case study, the overall decrease of the socio-economic benefit in this case study suggests that such reservation is not profitable to be implemented.

Chapter 7

Large scale wind integration

The second specific analysis consists of a set of two analyses with the same scope, which are presented in **Publication E** and its succeeding **Publication F**. The objective of these analyses is to assess the impact of large scale wind integration on the power system balancing. Therefore a comparison between the current system and an expected 2020 scenario with a high share of wind power production is done. In addition, the integration of national regulating power markets is considered. The potential benefit of using regulating reserves, which are located in the Nordic area, in order to balance WPP in continental Europe is investigated. The results show growing imbalances and reserve activation as well as increasing cost resulting in the regulating power market. With an integration of national regulating power markets, these costs can be reduced significantly, paving the way for an cost-effective integration of WPP in the European power system.

This chapter includes Sections V to VIII of **Publication F**, which are identical to Sections 7.3 to 7.6, with minor editorial changes. Section 7.2 is added, presenting a comprehensive overview on the modelling of the wind power production. As the second author of this **Publication F**, I am responsible for the simulations of the power markets, given the detailed wind power production.

7.1 Analysis introduction

The variability and limited predictability of power production on all time scales is one of the major challenges when it comes to large scale integration of WPP in the power system. In a liberalised electricity market WPP is traded in the day-ahead spot and intra-day market, based on wind speed forecasts. However, short term deviations, resulting in system imbalances, have to be handled in the regulating power market.

For WPP the whole balancing area has to be considered, as smoothing effects in large geographical areas can reduce the requirement for regulating reserves [130]. Besides the increasing production changes, there are wind forecast errors, resulting form the difference between scheduled and actual WPP. These deviations need to be compensated by the activation of regulating reserves, available to the power system.

In order to study the effects of increasing WPP on the regulating power market outcome, the reserve procurement and system balancing in the Northern European area is simulated and resulting costs are determined. The simulations are done for national regulating power markets as well as an integrated Northern European market for the 2010 and 2020 scenario, defined previously in chapter 4.

7.2 Wind power production

7.2.1 WPP Simulation

The simulated real time WPP is based on a mixed input data set including wind speed measurements and input values from the high resolution numerical weather prediction tool COSMO EU [119], cf. the definition of WPP in EMPS in chapter 4. To account for geographic smoothing effects due to widely dispersed wind production sites, 3200 wind power facilities are modelled individually, ranging from single turbines up to wind farms. This geographic spread of WPP results in less production variability as wind speed correlation decreases with distance [120]. However, centralized offshore wind farms in future WPP scenarios will pose more severe challenges to the system, as they do not comprise geographical smoothing.

The assumed installed WPP capacity for the 2020 scenario (see Table 7.1) is based on the TradeWind project [116]. The 2020 scenario is in accordance with the projects 2020 high scenario, resulting in almost a triplication of the currently installed WPP capacity.

7.2.2 WPP Forecast Error

Based on WPP forecasts producers are able to estimate their approximate WPP and reschedule their preliminary production portfolio. At the time of the day-ahead spot market clearing (12:00), the WPP forecast horizon is between 12 and 36 hours. The rescheduling of power production due to improving WPP forecasts has to be done via intra-day markets. Fig. 7.1 shows the hourly forecast errors for 3 and 24 hours ahead, which indicate the improving forecast

Table 7.1: Installed wind power production capacity per country [MW] in 2010 and 2020

Country	2010	2020
Norway	545	6600
Sweden	1250	10 000
Finland	350	3000
Denmark	3700	6000
Germany	24 900	57 300
Netherlands	2800	10 400
Belgium	1000	2950
Sum	34 245	96 250

over a descending forecast horizon and hence the significantly reduced need to balance WPP. Wind power producers are assumed to balance their production portfolio either by redispatch of their own production portfolio or in the intra-day market up to 3 hours before real-time.

It is expected that a rescheduling is much cheaper than settling the imbalances due to the forecast error in the regulating power market. A previous analysis [131] shows, that neglecting the possibility of the intra-day markets and using the 24 hours WPP forecast error as system imbalances would result in enormous costs of about 1.6 billion € per annum. Hence in this analysis, the 3 hours ahead wind speed forecast is used as basis for the WPP forecast error. The costs due to rescheduling, which occur in the intra-day market are not taken into account in this analysis. A more detailed analysis of the regulating power market outcome for different WPP forecast horizons is presented in succeeding Chapter 8.

Even though, the mean absolute forecast error for the whole simulated area is relatively low (218MW), the maximum forecast error rises up to more than 10 GW for the 3 hours ahead forecast (see Fig. 7.1) during extraordinary events like fast moving weather fronts.

7.3 Case Studies

The influences of WPP on system operation are studied based on five scenarios. Firstly place 2010 is simulated using the actual installed wind power capacity and the corresponding imbalances as a reference. Secondly, three cases for the 2020 scenario are simulated. Two different cases for the reserve procurement as well as the system balancing are defined. These cases are no market integration

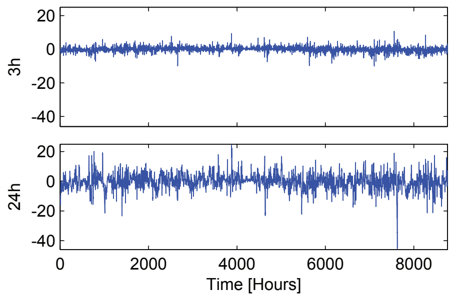


Figure 7.1: Aggregated wind power production forecast error [GW] for the modelled area in 2020

and full market integration.

7.3.1 Market integration

The case **no market integration** represents the current state. Regulating reserves have to be procured in the particular country. In countries split into different control areas e.g. Norway and Germany (see Fig. 3.2), reserve requirements are defined by control area; however, the procurement can be done countrywide under consideration of available transfer capacities. Exchange of balancing power with neighbouring countries is not possible.

Full market integration describes a future state in which regulating power markets in Northern Europe are fully integrated. Besides the procurement of reserves in the own country, they now can also be procured in the whole simulated area. However, as suggested by ENSTO-E [132] 50% of the required reserves must be procured in the own country.

7.3.2 Transmission reservation

The cross-border procurement of regulating reserves for full market integration is split into two cases. These cases analyse an additional reservation of transmission capacity for the exchange of regulating reserves on cross-border transmission lines, cf. chapter 6.

In the **no-reservation** case, full transmission capacity is used in order to clear the day-ahead market. Free transmission capacity after day-ahead market clearing is used for cross-border reserve procurement and the exchange of regulating energy.

In the case of **reserving** transmission capacity only 90% of the available cross-border transmission capacity is disposable to the day-ahead market while the remaining 10% are exclusively reserved for the cross-border procurement of regulating reserves. Further transfer capacity not utilized after day ahead market clearing is also viable for the exchange of regulating reserves.

Given available transmission capacity, exchange of regulating energy is enabled in the fully integrated market. This exchange results in the activation of the system-wide most economical reserves.

7.4 Results

The EMPS model is run with different hydrological years, to reflect the hydro inflow stochasticity. Solving the model results in the day-ahead market dispatch. One of the main results of the dispatch is the available capacity after the day-ahead market clearing. Fig. 7.2 to Fig. 7.4 depict the cumulative transmission of the HVDC lines connecting Nordic with continental Europe. The dotted black lines indicate the transmission limits. The graphs display the percentiles of the transmission dispatch duration curve, considering the different inflow years. Instead of analysing single transmission lines, the evaluation of transmission corridors (here Nordic to continental Europe), results in smoother duration curves and disposable transmission capacity during most of the time. It evinces, that only in wet years, during about 200 hours, all the transmission lines are congested in the same direction at the same time in the 2010 scenario (Fig. 7.2).

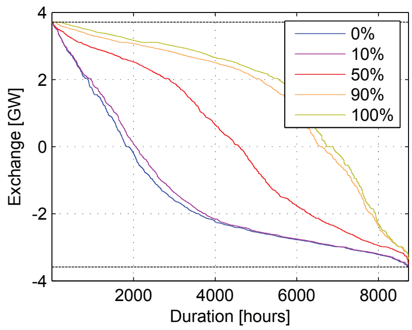


Figure 7.2: Transmission dispatch 2010

This value increases up to about 1500 hours in 2020 (Fig. 7.3), when there is full export on all the transmission lines from Northern to continental Europe. The remaining free transmission capacity can be used for cross-border reserve procurement and the exchange of regulating energy. However, also during congested hours a one directional exchange is viable (downward regulating reserves in this case).

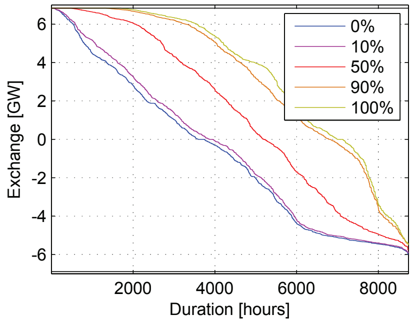


Figure 7.3: Transmission dispatch 2020 no reservation

Fig. 7.4 shows the case of transmission reservation, where bidirectional transmission capacity is always at disposal. As discussed in the previous chapter 6 capacity reservation comes at a decreased socio-economic benefit in the day-ahead market clearing. Thus, a trade-off between the day-ahead spot and the regulating power market is necessary.

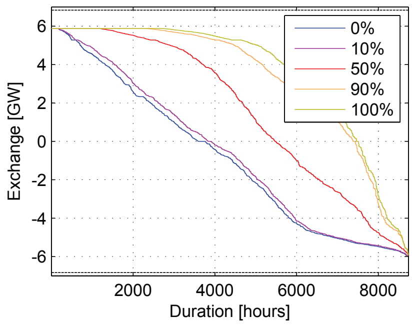
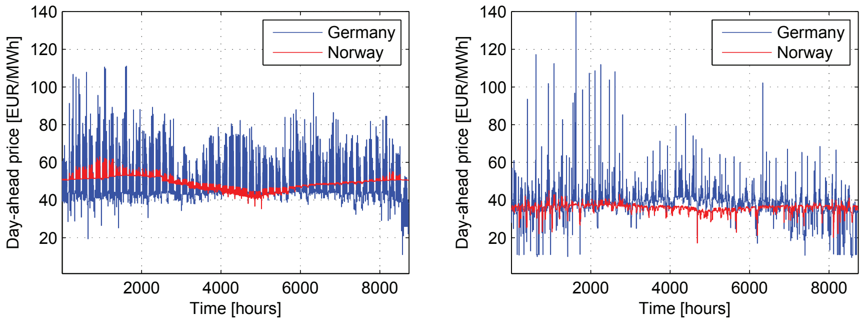


Figure 7.4: Transmission dispatch 2020 with reservation

Another important result are the day-ahead market prices (see Fig. 7.5), indicating the marginal production cost during a certain hour in the system. In a well-functioning regulating power market the regulating power prices lie in the vicinity of the day-ahead market prices. I.e. the day-ahead market price also gives a rough indication for the marginal production cost of the available regulating reserves. Comparing day-ahead market prices for the 2010 and 2020 scenario, it can be seen, that volatility increases in Germany, but decreases in

Norway. However, the average day-ahead market price is lower in both countries indicating cheaper regulating reserves in 2020 compared to 2010.



(a) 2010 (b) 2020

Figure 7.5: Day-ahead market prices Norway, Germany

Table 7.2 and Table 7.3 give an overview on the results of the regulating power market simulations for the defined scenarios and cases.

Table 7.2 presents results of the current market situation, without an integration of the Nordic and continental European regulating power markets. Due to the increased reserve requirements, the reserve procurement costs are more than doubled in 2020. The additional WPP in 2020 increase the system imbalances by about 90%. Hence, the gross reserve activation rises by about 80%. The fact that reserve activation increases less than system imbalances, is caused by the netting of imbalances within the Nordic system and in Germany. As new WPP mainly will be built in continental Europe, there only is a minor increase of imbalances and therefore reserve activation in the Nordic area. The balancing costs are estimated to increase only by about 25%, far less than the increase in reserve activation. The reason for that is the overall decrease of day-ahead prices in the 2020 scenario and the expected availability of more reserve capacity than in 2010.

Table 7.3 contains results for the full market integration case, i.e. the possibility of cross-border procurement of regulating reserves and the exchange of regulating energy is given. Again the 2010 scenario and two cases for 2020 scenario - with and without transmission reservation for the regulating power market - are analysed. In 2010 the average cross-border procurement is about 10% of the total reserve requirement (nearly only upward regulating reserves), resulting in a possible cost reduction of 40%. Fig. 7.6 depicts the annual average distribution and procurement of upward regulating reserves for this case. It can be seen that there is an export of reserves from Sweden and Norway to

Table 7.2: Regulating Power Market Outcome - No Market Integration

	2010	2020
Total reserve requirements [MW]	7080	13460
Procurement costs [M€]	146.5	343.6
Gross imbalance [GWh]	13637	24622
Gross reserve activation [GWh]	8945	14670
Gross reserve activation in the Nordic area [GWh]	3597	4209
Balancing costs [M€]	126.8	154.6

Denmark and Germany. The Danish import covers nearly 50% of the required reserves, which equals the limit set for the cross-border procurement of reserves. Surprisingly there also is an export of reserves from the Netherlands, which can be explained by its rather low reserve requirements.

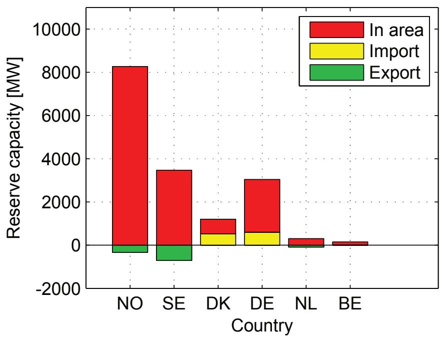


Figure 7.6: Reserve procurement and exchange in 2010 - full integration

As described previously it is assumed that there will be an increase in reserve requirements in 2020. With the additional transmission capacity, the cross-border procurement of reserves is more than doubled. Furthermore, the cross-border procurement will increase by another 15% in the case of reserved transmission capacity. Unlike 2010 there is a notable cross-border procurement of downward regulating reserves, of about 16% of the total cross-border procurement. Fig. 7.7 and 7.8 depict the annual average procurement of upward regulating reserves in 2020. There is no mentionable difference between the case with and without transmission reservation. Compared to 2010 it can be noticed, that due to the additionally installed hydro capacity in southern Norway, significantly more reserves are available in the system.

Fig. 7.7 and 7.8 show that the main additional export of regulating reserves

Table 7.3: Regulating Power Market Outcome - Full Market Integration

	2010	2020	
		no res.	with res.
Total reserve requirements [MW]	7080	13460	13460
Mean cross-border procurement [MW]	765	1854	2134
Procurement costs [M€]	88.3	248.3	233.6
Gross imbalance [GWh]	13637	24622	24622
Gross reserve activation [GWh]	6761	10464	10231
Gross reserve activation in the Nordic area [GWh]	4664	7824	8093
Regulating energy exchange [GWh]	3190	6340	8941
Balancing costs [M€]	91.8	85.5	74.5

is from Norway to Germany. When comparing the 2020 reserve procurement costs in Table 7.3 with the numbers of the no market integration scenario in Table 7.2, a cost reduction of about 30% is detectable.

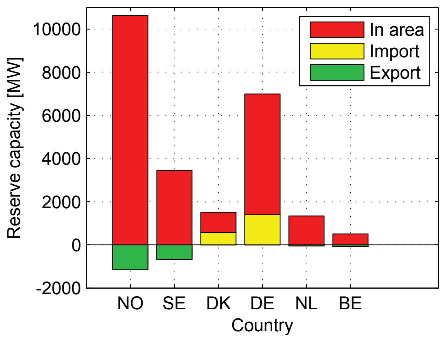


Figure 7.7: Reserve procurement and exchange in 2020 - full integration and no transmission reservation

Fig. 7.9 shows the cross-border procurement of upward as well as downward regulating reserves for 2020 with no transmission reservation. It displays that in most instances there is an export from Nordic to Continental Europe, but with exceptions during a minority of hours, in which the exchange characteristics are turned around. Furthermore, the maximum cross-border procurement of reserves is about 4.6 GW, which corresponds to 50% of the reserve requirements in the continental countries.

In the lower part of Table 7.3 results for the system balancing in the case of full market integration can be found. As stated above, imbalances nearly double

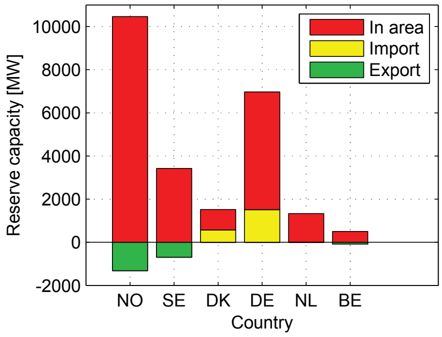


Figure 7.8: Reserve procurement and exchange 2020 - full integration with reservation

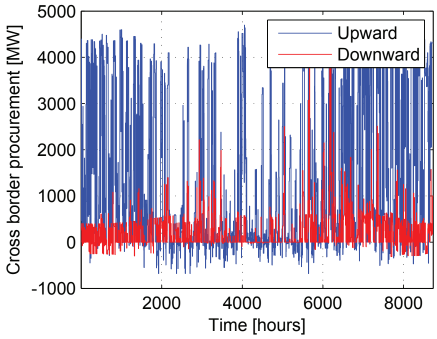


Figure 7.9: Hourly cross-border procurement of regulating reserves from Nordic to continental Europe in 2020 - no reservation

in 2020 compared to 2010. However, the activation of reserves only amounts up to about 40%-50% of the total imbalances, which is a drastic reduction, compared with the case of no market integration, where it is about 60%-70%. The reduction is achieved by cross-border netting of imbalances of the different countries. In the case of WPP, the netting can also be interpreted as the geographical smoothing of WPP. There is no significant further increase in imbalance netting in the case of transmission reservation, as the reserve activation only decreases by about 2%. Considering the reserve activation in the Nordic system solely, it can be seen, that its share of the overall activated reserves increases dramatically from 40% to 70% in 2010 and from 30% to 80% in 2020, when integrating markets. The share increases not only due to the decreased overall activation, but also due to an ascending activation in the Nordic area. Fig. 7.10 depicts the reserve activation duration curve in 2020 for the no and full market integration case. The characteristics discussed above, the overall decrease and Nordic increase of reserve activation, are clearly illustrated. Furthermore it can be seen, that there are about 5000 hours with no activation of reserves in the continental area, in case of full market integration.

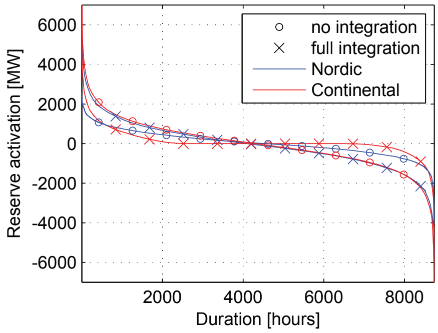
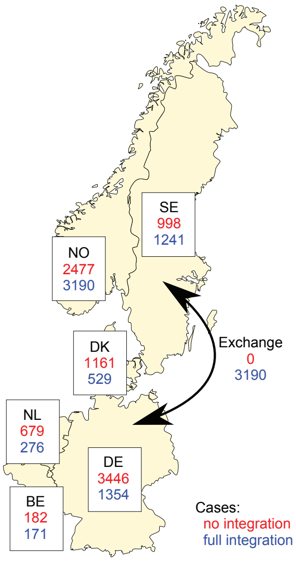


Figure 7.10: Nordic and continental regulating reserve activation in 2020 - no reservation

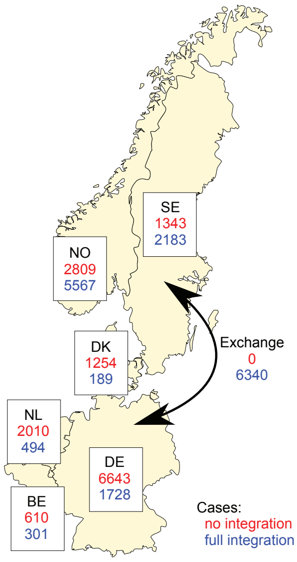
Fig. 7.11 shows the country wise activation of regulating reserves for the no and full market integration case in 2010 and 2020. It is obvious that market integration drastically reduces the activation of reserves in Denmark, Germany and Netherlands. As Belgium has no direct connection to the Nordic area, only a minor reduction in reserve activation is noticed. Due to its hydro resources, Norway is the main provider of regulating reserves.

As can be seen in Table 7.2 and Table 7.3, the reserve activation in the Nordic system, assuming a fully integrated market, increases by about 1100 GWh when being compared to the no market integration scenario in 2010. The exchange of regulating energy would be about 3200 GWh between the Nordic and the continental European system in 2010. The difference between these values result from the netting of imbalances between those systems. The same accounts for the 2020 scenario. With the reservation of transmission capacity, the exchange of regulating energy increases by further 30%.

Fig. 7.12 depicts the duration curve of the regulating energy exchange for all scenarios while Fig. 7.13 illustrates the hourly exchange for one year, taking the 2020 scenario without transmission reservation as an example. The duration curve shows, that there is an exchange of upward as well as downward regulating energy, where the net export of regulating energy from Nordic to continental Europe is less than 10% of the gross export.



(a) 2010



(b) 2020

Figure 7.11: Country wise annual regulating reserve activation [GWh]

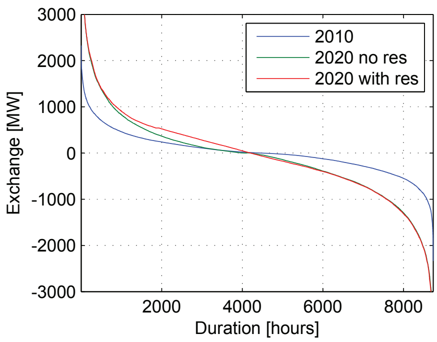


Figure 7.12: Duration curve of regulating energy exchange from Nordic to continental Europe

The hourly exchange of regulating energy in Fig. 7.13 is quite even distributed during the whole year. The maximum and minimum exchange is about 6 GW, which roughly equals the installed transmission capacity, between Nordic and continental Europe. However, this amount of transferred energy in combination with the quarter hourly changes comprises enormous challenges to the operation of the HVDC connections.

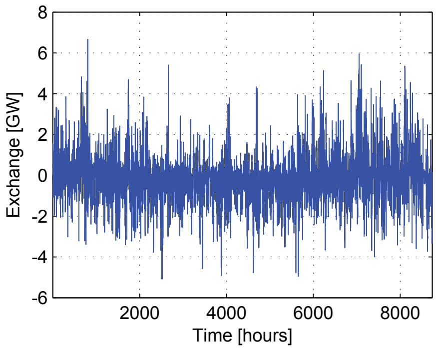


Figure 7.13: Hourly regulating energy exchange from Nordic to continental Europe 2020 no reservation

Finally, analysing the balancing costs shows that there can be high savings by integrating regulating power markets, amounting up to about 30% in 2010 and around 50% in 2020. With no market integration, the increasing system imbalances from 2010 to 2020 are accompanied by rising balancing costs. In case of integrated markets the system balancing costs decrease over the examined time period, which is in contradiction to expected results. A reason for that are additional possibilities of exchanging regulating energy with the Nordic system, due to transmission expansion and the increasing hydro capacity in the Nordic system, providing cheap regulating reserves. Another reason can be, as previously mentioned, the overall decreased day-ahead prices, also leading to lower costs for system balancing. While balancing costs decrease there is a significant increase in the costs for reserve procurement, leading to an overall increase in costs.

7.5 Discussion

System parameters, i.e. the power plant portfolio of thermal plants, inter-area transmission capacities, reserve requirements and WPP capacities are updated for the 2020 scenarios. It is attempted to incorporate the supposed system expansion in the upcoming years as realistically as possible. The influence and necessity of these modifications become obvious, when comparing the simulated market outcomes with results from a previous work [131]. In this previous work, the estimated balancing costs of about 1.6 billion € in 2020, are multiple higher than the 85.5 million € mentioned in this paper. The main drivers for this amazingly high gap are the additional available transfer capacities and the forecast length of WPP. The forecast length was reduced from 24h to 3h as it is assumed that the interim fluctuations are taken care of in the intra-day market, reducing the gross imbalance by about 40%. Trading on the intra-day markets implies shifting balancing responsibility from TSOs to wind power producers. Thus, costs for TSOs, which are analysed in this paper, will be reduced. In contrast costs for wind power producers will increase, which are not taken into account here. The increase of transfer capacities between Nordic and continental Europe opens up new possibilities of retrieving balancing services from the least cost source in an integrated market. This causes a further significant reduction of balancing costs.

7.6 Conclusion

The installation and integration of large amounts of WPP capacity into the power system comprises exceptional challenges. Amongst others, the procurement of regulating reserves and the system balancing are of outstanding importance.

The analyses include five scenarios for two market models simulating a non- and a fully integrated Northern European regulating power market. The regulating power market outcome without integration shows that gross system imbalances and gross activation of regulating reserves are almost doubled in the 2020 scenario. With an overall amount of 343 M€ the reserve procurement costs are more than twice as high as the 2010 results. The system balancing costs increase by about 28 M€.

Using the potential of a fully integrated market with its system-wide reserve procurement and exchange possibilities, the procurement costs could be cut down by 40% in 2010, while in the 2020 scenarios the costs are reduced by about 30%. Almost the same conclusion can be drawn for the balancing costs, being reduced by 50% to about billion 74 M€ in the 2020 scenario with a reservation of transmission capacity. As most of the cheap regulating reserves are situated in the Nordic area, their exchange will grow and become more important in future scenarios, whereas the activation of reserves in continental Europe will decrease by about 30%.

The implementation of transmission reservation for the exchange of balancing services leads to a rather small additional reduction of procurement and balancing costs, coming at the expense of a decreased socio-economic benefit in the day-ahead spot market.

The investigated scenarios confirm that WPP results in an enormous increase of activating regulating reserves, especially in a split market environment. However, regulating power market integration would significantly reduce the activation and hence the cost for reserve procurement as well as for system balancing.

Chapter 8

Reserve requirement levels

The final analysis addresses the requirements for the procurement of reserve capacity in the regulating power market. At first the impact of different forecast horizons of WPP on reserve requirements is assessed. Succeedingly a set of different reserve requirement levels is analysed, showing their influence on the regulating power market outcome.

This chapter includes **Publication G**. Succeeding Sections 8.3 to 8.5 are identical to Sections III and IV of the publication, with minor editorial changes. Section 8.2 is added in this thesis, stating important assumptions for the analyses.

8.1 Analysis introduction

Balancing supply and demand at every time instance is one of the crucial challenges in operating a power system. Beside load uncertainties and unplanned outages of power plants or transmission lines, the forecast of intermittent power production like WPP results in system imbalances. Different studies show, that integration of WPP is expected to increase system imbalances and hence costs in the regulating power markets, cf. [131, 133, 134]. Succeeding the more general expectations retrieved in those studies, this two-part analysis investigates the more specific questions:

- What is the impact of the WPP forecast horizons / quality on the regulating power market operation?
- How do different reserve requirements levels influence the regulating power market operation?

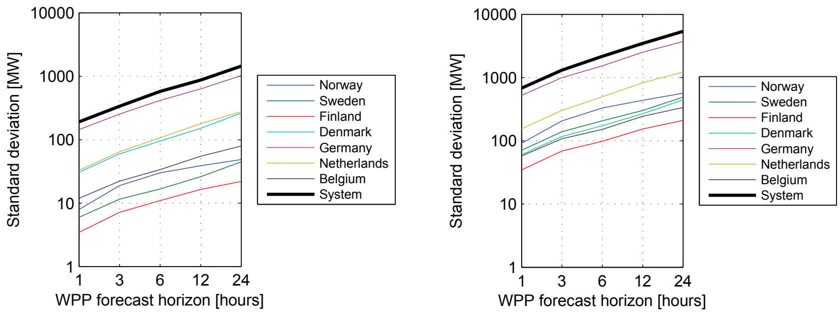
As a basis for defining reserve requirements the standard deviation of the WPP forecast error is utilized. In the analyses, the current situation of national regulating power markets and an integrated regulating power market are simulated.

8.2 Modelling assumptions

The analyses are executed with the previously presented power market models, including the day-ahead spot and the regulating power market. To assess the impact of increasing WPP penetration of the power system, the 2010 and 2020 scenario of the Northern European power system are utilised.

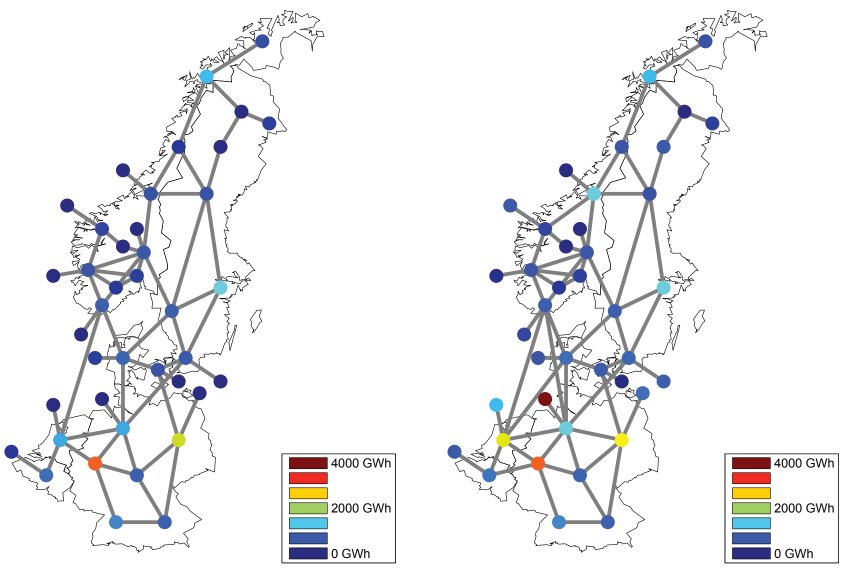
Wind power production WPP is expected to be one of the main drivers for future changes in the power system. As shown in Table 7.1, a significant increase of installed WPP capacity is expected, from about 34GW in 2010 to 96GW in 2020. Beside its intermittency, WPP is not perfectly predictable, but needs to be forecasted. These WPP forecasts imply an error, which is the main reason for the need of additional regulating reserves. The forecast horizons included in the analyses are 1h, 3h, 6h, 12h and 24h respectively. Fig. 8.1 shows the logarithmic plot of the WPP forecast error standard deviations ($\sigma\epsilon_h^{WPP}$) for individual countries and the aggregated system in 2010 and 2020. The WPP forecast error is taken from WPP simulations [135] using wind speeds forecasts from the COSMO EU weather model by Deutscher Wetterdienst [119]. The WPP forecast error increases significantly with a longer forecast horizon h. The standard deviation $\sigma\epsilon_{24}^{WPP}$ for the 24h ahead forecast is nearly 10 times as high as for the 1h ahead forecast.

System imbalances In addition to the WPP forecast error there are load forecast errors and unplanned outages of generation facilities, which result into additional imbalances in the system. To model these imbalances recorded data of 2010 is used, as described in chapter 5. An geographic overview of the total system imbalances including load forecast errors, unplanned outages and a 6h ahead WPP forecast for the 2010 and the 2020 scenario are shown in Fig. 8.2. The figure shows the annual sum of absolute positive and negative imbalances for each area. The expected future impact of WPP on system balancing is illustrated clearly. In 2010 the highest imbalances are observed in highly populated areas as western Germany, the Stockholm area and the Netherlands. Additionally, high imbalances occur in Eastern Germany, where there already is a high share of installed WPP. In 2020 the figure changes and the highest imbalances are observed from offshore WPP in the German North Sea.



(a) 2010 (b) 2020

Figure 8.1: WPP forecast error standard deviation $\sigma\epsilon_h^{WPP}$ for the modelled countries [119, 135]



(a) 2010 (b) 2020

Figure 8.2: Annual system imbalance with a 6h WPP forecast horizon

Reserve requirements Considering expected system imbalances certain requirements for regulating reserves are defined per control area / country. In the analyses a distinction is made between operating reserves R_{OP}, which refer to load imbalances and unplanned outages and WPP reserves R_{WPP}, which are dedicated to level out WPP imbalances. The total requirements are defined in an ad-hoc approach by summing up operating and WPP reserves[1].

The annual WPP forecast error standard deviation $\sigma\epsilon_h^{WPP}$ is chosen as the basis for the amount of WPP reserves R_{WPP}, cf. [121] and [136]. Operating reserves are defined considering current requirements implemented by TSOs. These are the requirements for Fast Active Disturbance Reserves (FADR) in RGN and for secondary reserves in RG CE, cf. chapter 5. Today, in Germany TSOs are responsible and in Denmark the TSO can be responsible for levelling out WPP imbalances. Thus, the current reserve requirements implemented in these both countries are decreased by necessary WPP reserves. The resulting operating reserves per country are stated in Table 8.1, which are used for the 2010 as well as the 2020 scenario.

Table 8.1: Operating reserves R_{OP} in MW 2010 and 2020

Country	NO	SWE	DK	DE	NL	BE
upward	1200	1220	525	2320	300	150
downward	1200	1220	525	1355	300	150

Reserve reduction, shut down and rationing Important variables in the analyses are a possible reduction of reserve capacity, the shut down of production and the rationing of demand. These are implemented to ensure feasibility of the solution.

In reality a possible reduction of reserve requirements corresponds to operating the system outside given regulations, e.g. outside the (n-1) criteria, which can also be seen in reality. A reduction of reserve requirements is assumed to be done at high prices for reserve capacity. The cost for reserve reduction is not included in the overall regulating power market costs[2].

[1] The main objective for the specification of reserve requirements is to define a set of different requirement levels, which accounts for the WPP forecast error. The definition of requirement levels is rather different in the regarded countries, from a simple approach, suggested by ENTSO-E [16], to a rather complex approach used in Germany [74]. As reserve requirements are defined in the same way for all the countries, the ad-hoc approach is chosen.

[2] As shown in Chapter 5, the costs for the reduction of reserve capacity are part of the objective function (Equation 5.54). However, these are just potential costs, describing the increased risk of operating the system with less reserve capacity. Hence, if reserve reduction occurs, these costs are withdrawn after the solution of the optimisation problem.

Shut down of production corresponds to either must-run units like nuclear power plants, heat-driven electricity production (district heating) or WPP. Contrarily, rationing corresponds to a curtailment of consumption, which can happen during reserve procurement, i.e. on a day-ahead basis or during real-time operation of the system. In the case of rationing during the day-head dispatch, exceptional actions can be taken in reality to hinder a curtailment. These actions are not implemented in the model, but solely described by a high cost. Rationing during system balancing is much more complicated, as it is not possible to drop the exact amount of demand. These situation also pose severe challenges to keep the system operational, resulting in a much higher cost.

8.3 Analyses

The analyses presented in this chapter include two power system scenarios (2010 and 2020) and two states of regulating power market integration, no integration (NoIn) and full integration (FuIn), as described in chapter 5.

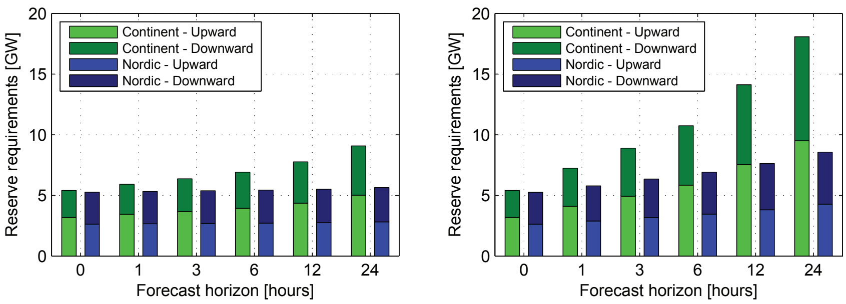
In subsection 8.3.1, the impact of different WPP forecast horizons and their inherent forecast errors on the regulating power market outcome is analysed. In the second part (subsection 8.3.2) the outcome for various reserve requirement levels is analysed.

8.3.1 WPP forecast horizons

The basis for the first analysis are different WPP forecast horizons and their resulting forecast error. As described in chapter 3, the basis for the regulating power market is a day-ahead market. Hence, settling all forecasted WPP in the day-ahead market would result in a forecast horizon of 12h to 36h. However, with shorter WPP forecasts available, trading can be done in intra-day markets in order to adjust the production dispatch. In the analyses it is assumed that the common day-ahead system dispatch resembles the situation after the final trades in the intra-day markets, i.e. no trades can be done before real-time system balancing.

Beside the strict length of a forecast horizon, these different horizons shall also represent improved forecasting techniques and hence better quality, resulting in fewer forecasting errors. The WPP forecast horizons used in the analysis are a perfect WPP prediction and forecasts for 1h, 3h, 6h, 12h and 24h hours ahead.

The underlying requirements for the procurement of regulating reserve are operating reserves R_{OP} plus WPP reserves ($R_{WPP} = 2 \cdot \sigma\epsilon_h^{WPP}$). The resulting reserve requirements are plotted in Fig. 8.3. There is no big dependency of the reserve requirements on the forecast horizon in 2010. However, using the approach of the standard deviation in 2020, results in more than a quadruplication of the reserve requirements.



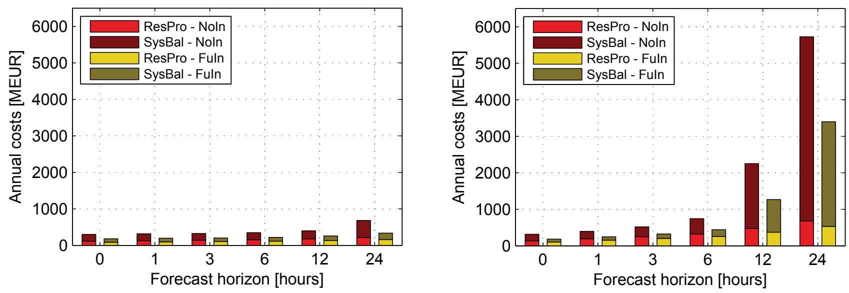
(a) 2010 (b) 2020

Figure 8.3: Reserve requirements of for different forecast horizons (sum of up- and downward reserve requirements)

The resulting outcome, i.e. the total costs in the regulating power market, including reserve procurement and system balancing are show in Fig. 8.4. In both, 2010 and 2020, costs increase with a longer forecast horizon. The costs with a perfect WPP forecast nearly equal in 2010 and 2020, as system imbalances are the same. However, the costs for the 24h ahead WPP forecast are eight times as high than the costs for the perfect forecast in 2020, but only two times as high in 2010. This points out the growing importance of high-quality WPP forecasting in the future. By an integration of regulating power markets, with cross-border procurement of reserves as well as their activation, a cost reduction down to about 60% can be achieved in all of the cases.

8.3.2 Reserve requirement level

An important design variable in regulating power markets is the amount of regulating reserves which are required to be available during system balancing, cf. [20]. As shown in the previous subsection, WPP will become a more important issue in regulating power markets, i.e. the system operation. One way to determine regulating reserves requirements is based on the WPP forecast error standard deviation $\sigma\epsilon_h^{WPP}$, cf. [121] and [136]. To analyse different reserve requirements, five levels are chosen. These levels are defined as follows:



(a) 2010 (b) 2020

Figure 8.4: Total regulating power market costs for different forecast horizons

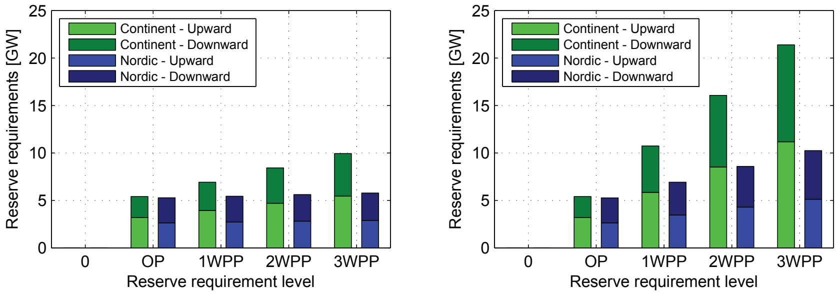
0	:	no reserves required
OP	:	R_{OP} only
1WPP	:	R_{OP} plus $R_{WPP} = 1 \cdot \sigma\epsilon_h^{WPP}$
2WPP	:	R_{OP} plus $R_{WPP} = 2 \cdot \sigma\epsilon_h^{WPP}$
3WPP	:	R_{OP} plus $R_{WPP} = 3 \cdot \sigma\epsilon_h^{WPP}$

For this analysis a WPP forecast horizon of six hours is assumed. The chosen WPP forecast horizon is arbitrary, but is assumed to be a reasonable choice between the best available WPP forecast and the possibility to reschedule production.

The resulting total reserve requirements for the defined reserve requirement levels in 2010 and 2020 are shown in Fig. 8.5. WPP forecast errors do not have a big impact on the reserve requirements in 2010, but a significant impact in 2020. A higher increase of reserve requirements occurs in continental Europe, due to more installed WPP capacity.

The cross-border procurement of reserves in the case of a full-integrated Northern European regulating power market is depicted in Fig. 8.6. The values shown are the annual average sum of reserves, which are required in RG CE areas, but are procured in RGN. This corresponds to an export of reserve capacity from RGN to RG CE.

In 2010 almost only upward regulating reserves are procured cross-border, as there are sufficient downward regulating reserve available in the continental system. Depending on the requirement level, the cross-border procurement amounts up to 1100MW on average, which corresponds to about one-fifth of

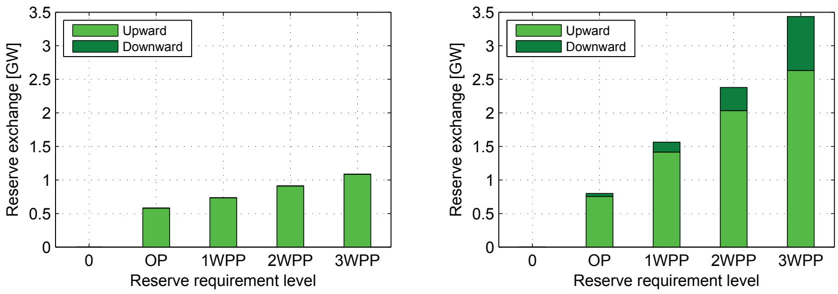


(a) 2010　　(b) 2020

Figure 8.5: Reserve requirements for different reserve levels (sum of up- and downward reserve requirements)

the upward reserves required in the continental system.

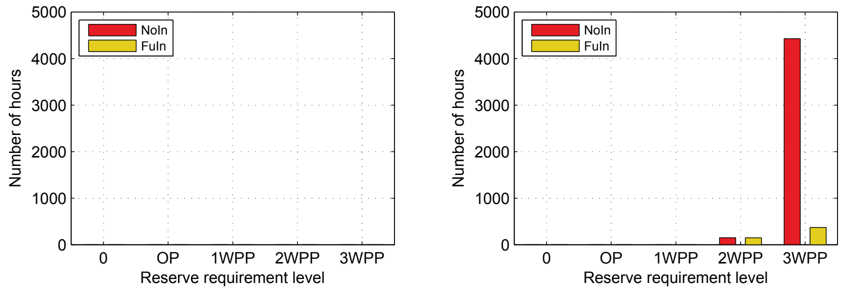
In 2020 the cross-border procurement of regulating reserves becomes much higher, now including a considerable share of downward reserves. The reserves procured cross-border account for about one-fifth of the required upward reserves and additionally one-tenth of the downward reserves.



(a) 2010　　(b) 2020

Figure 8.6: Average export of regulating reserve capacity from RGN to RG CE

In the case of insufficient reserve resources, the requirements are reduced, to ensure feasibility of the solution. The number of hours with requirement reduction in the system is plotted in Fig. 8.7. A reduction of requirements only occurs in the 2020 scenario. Furthermore, the reduction only happens for the reserve levels 2WPP and 3WPP, where it is highest in the case of non-integrated markets. The shortage of reserves is mostly observed in the Netherlands, Northern and Eastern Germany. Reductions up to 60% of the requirements occur in the Netherlands. In 2020 and the 3WPP reserve level the requirements cannot be met in about 4500 hours of the year, i.e. half of the time. This indicates probably unnecessary high requirements.



(a) 2010 (b) 2020

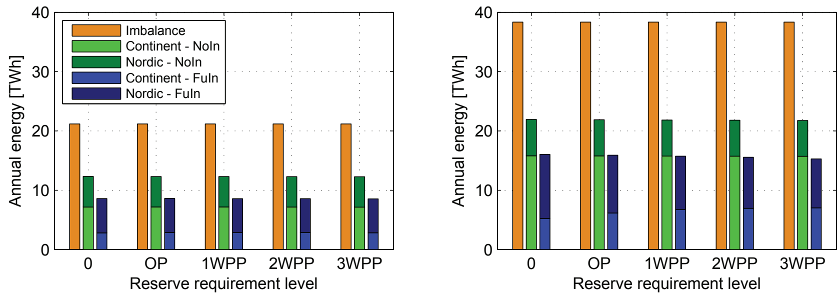
Figure 8.7: Annual number of hours with a reduction of reserve requirements

Fig. 8.8 illustrates the system balancing in 2010 and 2020. Activation of reserves includes the shut down of production and rationing of demand. The overall system balancing is nearly the same for all requirement levels in 2010 and 2020. In the case of individual national regulating power markets, no differences in reserve activation are perceived, as the reserves have to be activated in the countries, where the imbalances occur. However, in the case of full integration an exchange of balancing energy is possible. Thus, there are differences in the activation between the defined requirement levels. Less reserves are activated in the Nordic area at higher requirement levels, i.e. the exchange of balancing energy is decreased. At higher requirement levels a larger amount of spinning (cheaper) reserves is available in the continental areas and hence activated.

In 2010 as well as 2020, an integration of regulating power markets decreases the activation of regulating reserves significantly to about two-thirds due to the netting of imbalances in opposite directions, which occur in different countries.

The shut down of production, mainly WPP, is plotted in Fig. 8.9. In 2010 in the case of no reserves required, a large amount of production is shut down (1TWh), while high rationing occurs simultaneously. Shut down is reduced drastically with a procurement of reserves and decreases further at higher requirement levels.

In 2020 the situation changes drastically. Shut down of production as well is the highest for no procurement of reserves in the no integration case. As in 2010 this comes with simultaneous rationing. However, in 2020 the reduction

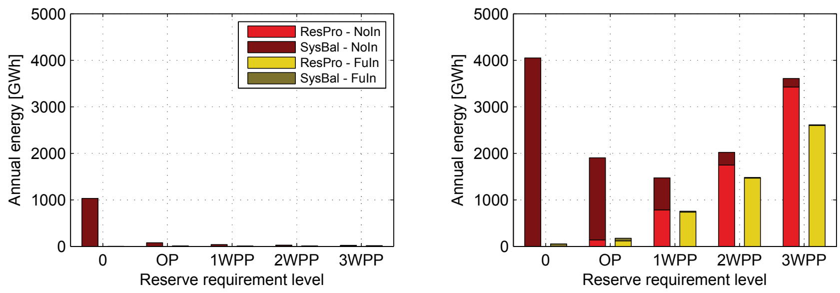


(a) 2010 (b) 2020

Figure 8.8: Gross system imbalance and reserve activation for different reserve levels

of shut down at higher requirement levels is not as much as in 2010 and a total minimum shut down is observed at a requirement level of 1WPP. For higher requirement levels shut down increases again, significantly during the reserve procurement process. Here, WPP needs to be shut down in order to start up thermal power plants, which can provide regulating reserves.

In the full integration case, nearly no shut down occurs in 2010. Almost the same accounts for the system balancing in 2020. However, there is significant shut down during reserve procurement in 2020, amounting up to 2.8TWh for the 3WPP reserve level.

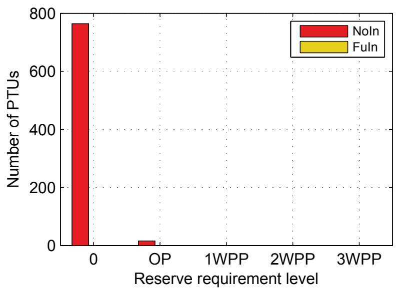


(a) 2010 (b) 2020

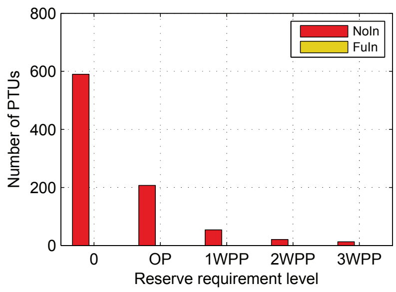
Figure 8.9: WPP shut-down during reserve procurement and system balancing for different reserve levels

In contrary to the shut down of production, there can be rationing of demand. In Fig. 8.10 the annual sum of PTUs, when rationing occurs in the system is plotted. In contrast to the energy, which is plotted for the shut down, the number of PTUs is chosen here, as every time rationing occurs the operation of the system is jeopardised, which can lead to serve challenges. In 2010 and 2020 a total rationing of 14GWh respectively 21GWh occurs for no procurement of reserves in the case of no market integration. This complies to rationing during 764 PTUs in 2010 and 590 PTUs in 2020, which certainly is not acceptable in the view of security of supply[3]. Most of the rationing is observed in Denmark, due to its high share of WPP and limited regulating reserves. In 2010, with the sole procurement of the operating reserves the number of PTUs with rationing is reduced to 16 and at 1WPP down to zero (see Fig. 8.10a). In 2020 even with a reserve level of 3WPP the number of PTUs with rationing is only reduced down to 13 (see Fig. 8.10b). Now rationing not only occurs in Denmark, but also Belgium, the Netherlands and Northern Germany, due to the high expansion of WPP. Together with the reduction of reserves (Fig. 8.7), it illustrates that the system would be operated at its limits.

With the integration of regulating power markets and the possible exchange of balancing energy, rationing does not occur for any of the reserve requirement levels. It shows, that there are sufficient reserves available in the whole system, it is solely necessary to utilise these reserves system-wide. Comparing the full integration case with no integration clearly points out the benefit of market integration in the view of operational security.



(a) 2010



(b) 2020

Figure 8.10: Annual number of PTUs with rationing during system balancing

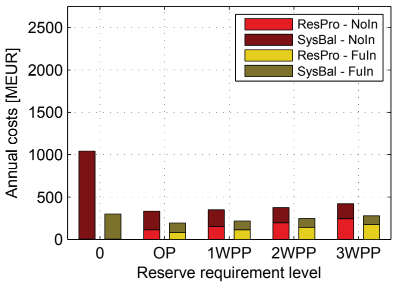
Interestingly enough, there is no rationing and no significant shut down in the case of full market integration, when there are no reserves required. This implies, there are actually sufficient reserves available in the whole system and would not be necessary to be procured. A further implication is, that beside

[3]The common accepted limit for rationing is 1h (4 PTUs) per annum.

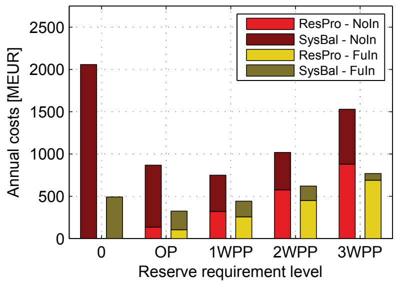
the sufficient availability of reserves, there is also sufficient transmission capacity available to provide exchange balancing energy during system balancing.

The level of reserve requirement has a significant impact on the total costs in the regulating power market as well, shown in Fig. 8.11. Plotted are the socio-economic costs, which occur during reserve procurement and system balancing. In the case of no reserve requirements, there are only costs due to system balancing. With this level and no integration enormous costs occur during system balancing, mainly due to rationing.

In 2010, minimum overall costs are observed for the reserve level OP in the case of no as well as full market integration. With an increased requirement level the overall costs become higher. While there is a strict increase of reserve procurement costs, there is a decrease of the system balancing costs down to about 175€/MWh and 100€/MWh for no and full market integration respectively. Today's implemented reserve requirement level corresponds to approximately 1WPP (see the definition of reserve requirements in 8.2), which indicates a slight over procurement of reserves in an optimum socio-economic view.



(a) 2010



(b) 2020

Figure 8.11: Total regulating power market costs for different reserve levels

The total regulating power market costs increase significantly in 2020, especially for the no market integration case. The highest costs are observed likewise for the no reserve level. The overall cost minimum in the no market integration case is observed at a reserve level of 1WPP, but it still is at OP for full market integration. Equally, the increase of reserve procurement costs and decrease of system balancing costs at higher reserve requirement levels can be spotted. But system balancing costs actually increase again for the 3WPP reserve level in the case of no market integration. The cost increase is due to the utilization of more expensive regulating reserves[4].

[4]In the case of high reserve requirements a lot of thermal plants have to be started up to provide regulating reserves. This includes plants with higher marginal production costs,

Furthermore, the analysis points out, that with an integration of regulating power markets socio-economic costs can be reduced down to about 60%. There is a cost reduction for the procurement of reserves as well as for their activation. During reserve procurement costs are reduced due to the utilisation of Nordic hydro reserves and the preventition of unnecessary starting up of thermal power plants. The costs for balancing the system are reduced, due to netting of imbalances and hence less reserve activation. These savings indicate the improved efficiency of utlising reserves, which are available in the system. Together with the possible shut down and rationing it evinces, that rather low reserve requirement levels are necessary and economically optimal.

8.3.3 System overview / development

In contrast to Fig. 8.2, showing the geographic distribution of system imbalances, Fig. 8.12 and Fig. 8.13 illustrate the location of procured and activated regulating reserves in 2010 and 2020 respectively. Shown are figures for the 6h ahead WPP forecasts and the 1WPP reserve requirement level. There is no integration of regulating power markets in 2010, while a full integration of markets is expected in 2020.

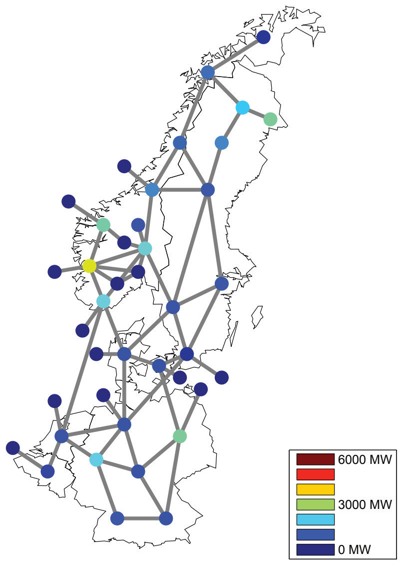
The available reserves after the reserve procurement for these two representative cases are depicted in Fig. 8.12. There will be no big change in the continental area, where approximately the same reserves are available in 2010 and 2020. However, the availability of reserves in the Nordic area increases, especially in southern and south-western Norway. Mainly reserve capacity from this part of Norway is exported to continental Europe in 2020, which can then be used to balance WPP in the North Sea area.

Likewise during system balancing (shown in Fig. 8.13) a clear change from activating regulating reserves in continental Europe to an activation of reserves in Nordic Europe is observed. The increased reserve activation reaches up to the most northern areas, but especially hydro resources in southern and south-western Norway are utilised to balance the system. Also with a significant increase of imbalances due to WPP expansion, reserve activation in continental Europe is almost constant.

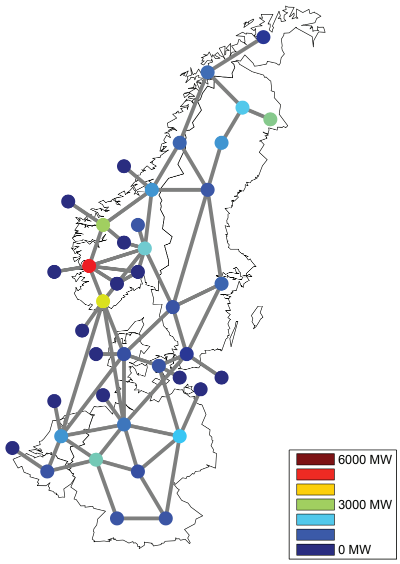
8.4 Discussion

As described in chapter 5 several simplifying assumptions are taken in the course of modelling the regulating power market. Regulating reserves used up to now in the Nordic system are manually activated reserves. Thus, it is assumed that

likewise resulting in higher marginal regulating costs.



(a) 2010



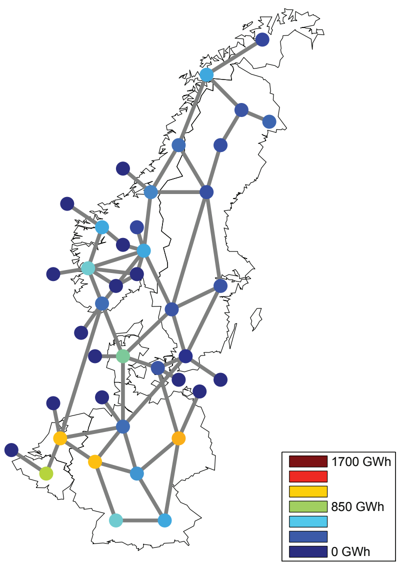
(b) 2020

Figure 8.12: Reserve procurement for 6 hours WPP forecast and 1WPP requirement level - Geographic distribution

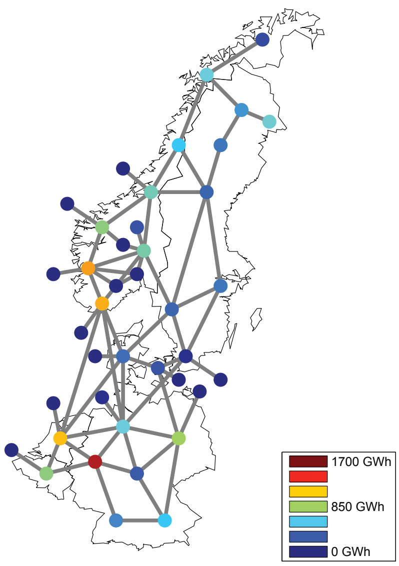
hydro units do not need to be started up to provide reserves and that they can provide their full capacity as reserves. This probably over estimates the availability of regulating reserves in the Nordic area. However, when comparing the available reserves with the potential cross-border procurement of reserves from the Nordic area, it shows that these cross-border procured reserves are only minor compared to the available reserves.

A surprising result is that rather low levels of reserve requirements result in no rationing and hence low system balancing costs. One reason for this may be, that average values over one PTU are used for imbalances, shaving off peaks. Another issue is the perfect market implementation, assuming that all capacity (which can provide regulating reserves) is available during system balancing, regardless if it was procured or not. This can explain why so few rationing is observed, when no reserves are required. Moreover, some of the thermal plants are assumed to be able to provide non-spinning reserves at high costs. These plants step in for balancing in this case. However, the analyses clearly demonstrates, that an integration of markets significantly reduces the risk of rationing, as none is observed even without a procurement of reserves.

A further issue is the efficient utilisation of large scale WPP in the power



(a) 2010



(b) 2020

Figure 8.13: Reserve activation for 6 hours WPP forecast and 1WPP requirement level - Geographic distribution

system. It is argued that with increasing WPP more regulating reserves are necessary, which is also confirmed in the first part of the analyses. However, in the second part it is illustrated that an increase in reserve requirements possibly results in an increased shut down of WPP in order to start thermal power plants, which can supply regulating reserves. Thus, the overall WPP production is reduced again. Solutions to this challenge are various. One can be to define the optimal reserve requirements, based on the least WPP shut down. The shut down not only includes WPP, but also other must-run power plants like nuclear or lignite power plants. Their decommissioning and substitution with thermal power plants, which are suited better to provide regulating reserves, would likewise reduce the shut down of production. Another possibility could be to include WPP itself for reserve provision as discussed in [63] and defined in the grid code of the Irish power system [137]. The final and suggested option is the integration of national regulating power markets, making regulating reserves in the Nordic system available to the continental European system and thus significantly reducing the shut down of production.

In Europe the bulk energy is traded on the day-ahead spot markets, which results in the system dispatch fr the next day. In the case of varying renewable energy sources, such as WPP, this implies a production forecast horizon of 12 to 36 hours, assuming a day-ahead spot market clearing at noon. This forecast is approximated with the 24h forecast horizon in this analysis. As it is shown in the analysis, shorter forecast horizons lead to a significant reduction of imbalances and hence costs in the regulating power market. It is argued that WPP producers have the ability to adjust their portfolio given updated and improved forecasts. In order to do so, WPPs either need own re-dispatchable production capacity or have to trade on intra-day markets, which are not regarded in the previous analyses. By trading in intra-day markets, parts of the responsibility for balancing the system is taken over by WPPs from TSOs. Thus, TSOs face less imbalances in real-time and hence reduced costs. This reduction come by shifting the costs from the regulating power market to the intra-day markets.

By the utilisation of intra-day markets, it can be argued that the remaining forecast error, which needs to be regarded for system balancing is an 1h ahead forecast error, which complies with the closure time of intra-day markets. But validity of this assumption, intra-day markets need to be liquid, which is not the case so far in Northern Europe, cf. Weber [138]. Furthermore, close to real-time trades in the intra-day market are certainly based on fast-changeable production capacity, which likewise can be used in the regulating power markets. Thus, it can be assumed, that costs in the intra-day market converge to the costs in the regulating power market with decreasing forecast horizon.

The analysis of various WPP forecast horizons shows a tremendous difference for total costs (in the 2020 scenario) in the regulating power market, with around 400 million € using the 1h ahead WPP forecast, up to more than 5 billion € using the 24h ahead WPP forecast. The increase in socio-economic costs due to additional WPP lies somewhere in between. The figures for the 24h ahead WPP forecast certainly overestimate the costs, as there still is sufficient time to adjust the system dispatch. However, the figures for the 1h ahead and 3h ahead WPP forecast underestimate the socio-economic costs, as the trade in the intra-day markets is not regarded. Especially on this short horizons, these costs are close to the ones which would occur for system balancing. Thus, the 6 hour forecast horizon is chosen as the basis for the second part of the analysis, assuming that succeeding trades on the intra-day markets are only marginal.

In order to assess the total socio-economic costs of integrating large amounts of WPP in the system, all of the physical power markets, encompassing the day-ahead spot-market, intra-day markets and the regulating power market with the reserve procurement and system balancing have to be regarded.

8.5 Conclusion

The expected increase of WPP capacity in Northern Europe with its inherent production forecast error will result in higher system imbalances. To level out these imbalances regulating reserves are required. The analyses assess the impact of different WPP forecast horizons and a set of different reserve requirements in the current power system (2010) and a future scenario (2020) with high WPP penetration.

The analysed WPP forecast horizons reach from a perfect WPP prediction to a 24h ahead forecast. Shorter forecast horizons lead to a significant reduction of system imbalances and hence less regulating reserves are required, resulting in lower regulating power market costs, while the resulting cost increase on intra-day markets is not regarded here. Interpreting the shorter forecast WPP horizon as improved WPP forecast, which can be expected in the future, the potential cost savings become tremendous in 2020. This clearly points out the value of high-quality WPP forecasts.

For a secure and efficient operation of the power system the definition of the reserve requirement level in the power system is of high importance. The resulting socio-economic optimal reserve requirement levels are rather low. While WPP does not have a big impact on the regulating power market outcome in 2010, it impacts the outcome significantly in 2020. Without an integration of national regulating power markets in 2020, the power system is operated at its limits, resulting in unacceptable rationing of demand, significant shut down of production and high costs in the regulating power market. With an integration of regulating power markets, rationing can be avoided, resulting in a securer operation of the system. Likewise much less production will be shut down and the costs in the regulating power market are reduced.

The analyses show that prospectively growing WPP will cause a significant cost increase in the regulating power market. However, when integrating the Northern European regulating power markets these costs can be reduced by approximately 40% (300 million € in the case of a 6h ahead WPP forecast), while the system security is increased, due to an efficient system-wide utilisation of all available regulating reserves.

Chapter 9

Conclusion and future research

This chapter finalises the thesis. Section 9.1 summarises the main conclusion of the previous chapters including the model development and analyses. Recommendations for potential further developments of the regulating power market model and future research topics are given in section 9.2.

9.1 Conclusion

To ensure the secure operation of the power system it is crucial to balance the production and consumption of electricity continuously. The change of the European power system towards sustainable power production leads to a higher variability and less predictability of power production. Thus, increased imbalances can be expected in the power system. To prospectively ensure the system balance, more regulating reserves are required in the power system.

Due to its unique characteristics, the Nordic and particularly the Norwegian hydro-based power system is capable to provide such balancing services to continental Europe. As the Nordic and the continental European power system are not synchronously connected, balancing services have to be exchanged via HVDC lines. Hence, the exchange of frequency containment reserves (primary control) is put aside in this thesis and the scope is set on the exchange of frequency restoration and replacement reserves (secondary and tertiary control).

In Europe balancing services are traded through national regulating power markets. To enable an exchange of balancing services across borders, an integration of these national markets is necessary. This development might eventually lead to one multinational European regulating power market. There already is large progress in the coupling and integration of European day-ahead spot markets, while several pilot projects are commenced for the integration of European regulating power markets.

The main part of the research, documented in this thesis, is dedicated to the development of a mathematical model for the study of national regulating power markets and their integration. This regulating power market model is based on a common day-ahead spot market model. It includes detailed data models of Northern European power system for the current state (2010) and a future scenario (2020). These power system scenarios are utilised to analyse the future power market outcome and assess the benefit of integrating national regulating power markets in Northern Europe.

Day-ahead spot market

In 2020 large wind power production capacity is expected in the system, resulting in a significant share of electricity production from this source. In Germany a significant reduction of nuclear power is expected, which is in line with current policies. In addition, it is assumed that the increased wind power production substitutes a certain share of base-load production from lignite power plants, while hard coal and gas-fired power plants are still needed as reserve capacity. The simulations show, that there are considerable changes in the operation of the power system, when moving from the 2010 to the 2020 scenario.

The impact of stochastic inflow to the Nordic system is reduced, but due to the wind power production a higher volatility of the system dispatch and consequently of electricity prices is observed. However, the average electricity price decreases in the Nordic area as well as in continental Europe. Furthermore, the operating hours and profit margins for thermal power plants are reduced substantially, which challenges their profitability. In a free market environment the non-profitable power plants will be mothballed or decommissioned completely, if there is no additional support. Finally, with the significant increase in interconnection capacity, the exchange between the Nordic area and continental Europe is nearly doubled.

Regulating power market

To assess the regulating power market outcome, a dedicated mathematical model is developed. The regulating power market model explicitly addresses the exchange of balancing services between the Nordic and continental European power system. Therefore, available transmission capacity is taken into account for the exchange of reserve capacity as well as balancing energy across national borders. With a set of different cases the model is utilised to assess a stepwise integration of the Northern European regulating power markets.

A comparison with the recent integration of the German regulating power markets shows similar results in the case of system balancing of about 200 million €. Whereas the benefit resulting from the system-wide reserve procurement is lower than observed in reality (20 million € in the model, 100 million € in reality). There are two reasons for the discrepancy. Firstly, the market design in the model assumes an integrated clearing of the day-ahead spot market and the procurement of reserves. This results in a more efficient dispatch than achieved by current practices in reality. Hence, there already are lower costs for the procurement of reserves before the market integration. Secondly, a perfect market is assumed, neglecting potential market power. Assessing the integration of Northern European regulating power markets shows significant additional benefits. With the possible exchange of reserve capacity on average 20% of reserve capacity, which is required in the continental area is procured in the Nordic countries. This results in savings of about 40 million €, which are potentially even higher in reality as discussed above. The activation of regulating reserves can be reduced by 40% due to system-wide netting of imbalances, resulting in extra savings of about 100 million €.

Altogether, the integration of regulating power markets could result in significant savings already in the 2010 scenario. Illustrating its capability of simulating regulating power markets and their outcome, the developed model is used as basis for further analyses.

Transmission capacity reservation

The exclusive reservation of transmission capacity for the utilisation in the regulating power market leads to an increased exchange of balancing services. This likewise results in decreased reserve activation, due to more imbalance netting. In 2010, this reservation reduces the costs in the regulating power market by about 20 million € per annum. However, this transmission reservation results in much higher losses on the day-ahead spot market clearing, than the savings that are achieved in the regulating power market. Furthermore, the day-ahead market losses are much higher for a 10% reservation than for a 5% reservation, which indicates a non-linear increase. Thus, a small reservation on single transmission lines might result in a socio-economic surplus. But the analysis clearly shows the importance of the impact on the day-ahead market in such an assessment.

Large scale wind power production

The prospective integration of large amounts of wind power production capacity into the power system from 34GW in 2010 up to 96GW in 2020 comprise challenges to the operation of the power system. To that, the assumed forecast horizon of wind power production is essential for the estimation of costs in the regulating power market. With a detailed 3h ahead forecasts and simulations of wind power production, the regulating power market outcome is analysed in 2010 and 2020. Therefore, it is assumed that wind power producers are able to adjust their production portfolio through trading on intra-day market, which requires liquid intra-day markets. The potential costs for the additional trade in intra-day market has not been assessed in this research.

Up to 2020 (in the case of national regulating power markets), the simulations show a doubling of system imbalances due to increasing wind power production capacity and hence activation of regulating reserves. Assuming a 3h ahead forecast for wind power production results in a total cost increase of about 230 million € in national regulating power markets up to 2020. With the integration of regulating power markets, reserve procurement costs can be reduced by about 30% and the cost for system balancing by about 50%. Together the potential savings amount to approximately 170 million € per annum.

The significant cost increase up to 2020, especially in the case of national regulating power markets, illustrates the impact of the expected high share of wind power production in the system. The potential savings point out the value and importance of integrating regulating power markets in Northern Europe. These savings can account for approximately 70% of the cost increase in the regulating power markets caused by increased wind power production.

Reserve requirement levels

Succeeding the simulation for a specific case of large scale wind power integration in the system, the impact of different wind power forecast horizons and their inherent forecast error on the outcome of the regulating power market is analysed. Furthermore, a set of different reserve requirements levels and their regulating power market outcome as well as impact on the system operation is assessed.

Shorter forecast horizons, resulting in reduced wind power forecast errors lead to a reduction of costs in the regulating power market. These cost reductions become significant in the 2020 scenario. The costs in the regulating power market are approximately 5.5 billion € for the 24h forecast horizon, while they would be only about 500 million € for the 3h forecast horizon (in the case of national regulating power markets). This indicates the value and importance of good quality wind power production forecasts and short forecast horizons. Shorter forecast horizons however, require additional trading of intra-day markets, which need to be liquid and cause additional costs to market participants, which are not regarded in the analysis.

Moreover, the analysis shows that in the case of national regulating power markets, the system is operated at its limits in 2020. This results in rationing of reserve capacity and an increased number of hours with rationing of demand, jeopardising system security. Concurrently, independent national regulating power markets result in high costs for the procurement of reserve capacity and the system balancing. An integration of regulating power markets not only significantly reduces the costs in the regulating power market down to about 60%, but also increases system security, due to an increased availability of regulating reserves in the power system.

The Nordic, especially the Norwegian hydro based power system, with its high production flexibility is capable to provide balancing services, which can be used in the continental power system. Mostly there is sufficient transmission capacity available after the day-ahead spot market clearing, in order to exchange balancing services. Even in the case of a full utilisation of the transmission capacity, exchange of balancing services is possible in the reverse direction. Furthermore, a redispatch of the system is possible to free up transmission capacity, if the redispatch is socio-economically beneficial.

The integration of regulating power markets results in the cross-border procurement of a significant share of reserve capacity, particularly from Germany, the Netherlands and Western Denmark in the Nordic area. Furthermore, the activation of regulating reserves is reduced by about 40% due to netting of imbalances. As discussed above, the assumption on the forecast horizon of wind power production has a significant impact on the outcome of the regulating power market. A shorter length of the forecast horizon implies a shifting from the regulating power market to intra-day markets, which is not regarded in the analyses. Assuming a 6 hours forecast horizon for wind power, the integration of Northern European regulating power markets would lead to savings of at least 140 million € in 2010 and at least 300 million € per annum in 2020. The three main reason for the savings are:

- The availability of free transmission capacity after the day-ahead spot market clearing for the exchange of balancing services
- The cheaper provision of regulating reserves from hydro power plants which are located in the Nordic area, compared to thermal power plants, which are located in continental Europe
- The reduced activation of regulating reserves due to the netting of counteracting imbalances in different control areas / countries

The research quantifies the significant cost increases in the regulating power market, which the future power system is expected to face. Furthermore, it shows that a regulating power market integration counteracts this cost increase, while the system security is improved. This can be achieved on the basis of an efficient system-wide utilisation of all available regulating reserves.

9.2 Future research

The main objective of the research was the development of a regulating power market model for Northern Europe, explicitly addressing the cross-border exchange of balancing services. Corresponding to the two main parts of the thesis, recommendations for future research can be mainly split in two areas, modelling issues and analyses.

As discussed in the previous chapters simplifications are necessary to implement the mathematical model of the regulating power market. Future research can tackle several issues. The most important issue, already mentioned in the project statement is the determination of costs for balancing services. Estimates on these cost are done during the research, which however are quite general. An improvement of these estimates is of significant importance to achieve precise economic results for the outcome of regulating power market integration.

A modelling issue is the explicit implementation of secondary and tertiary regulating reserves. So far the division is done in spinning and non-spinning reserves. With the introduction of AGC in the Nordic power system, a provision of secondary reserves to continental Europe can be introduced. However, it can be expected, that hydro power plants can provide less reserves based on AGC than with manual activation. Thus, the explicit modelling of automatic activated reserve is necessary for the improvement of the model.

Another issue regards the sequence of power markets. As stated in the model description the reserve procurement follows the day-ahead market clearing, while in most European countries the sequence is inverse. For a better representation of reality the latter market sequence should be implemented. Moreover, as regulating power markets become more important for intermittent power producers as well as balancing service providers, a trade-off between the day-ahead spot and the regulating power market will become crucial. Thus, a coupling of the regulating power market model with the day-ahead spot market model is certainly of interest, which provides a feedback of the regulating power market outcome to the day-ahead spot market model.

Finally, the modelling of intra-day markets should be addressed. As stated previously, by trading in intra-day markets, balancing responsibility is shifted from TSOs to power producers. This likewise implies a shift of costs from the regulating power market to intra-day markets. In order to answer the question of the overall socio-economic cost increase due to more varying and not perfectly predictable power production, the trade on all physical power markets has to be regarded.

The set of analyses which is presented only covers selected topics, based on a 2010 and 2020 scenario. The EU 20-20-20 targets are only an intermediate step to a sustainable European power system. The development and implementation of future scenarios for 2030 or 2050 with further significant increases of power production from renewable sources are certainly of interest. It becomes particularly interesting, when the installed generation capacity from renewable sources increases to a level, where traditional thermal production capacity is driven out and not adequate to serve the demand of electricity. It can be expected, that in this case an integration of regulating power markets is not only beneficial, but indispensable. The main location for new renewable energy production facilities is expected to be the North Sea area. Hence, it will be of importance to include not only Northern Europe, but extent the modelled area to the UK and potentially France, encircling the North Sea. These analyses should include a potential offshore grid.

The developed regulating power market model has the objective of maximising the social welfare in the modelled area. The research shows that the integration of regulating power markets results in cost reductions. However, European power markets encompass several different countries as well as several different types of market participants. In this regards, the outcome for the different countries respectively different market participants is of interest. Among all the market participants there will be winners and losers. Assessing the outcome for different groups of participants respectively countries can help to identify the potential motivation for or resistance against multinational regulating power markets and estimate the transfer of profits which would be necessary to achieve a common benefit.

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