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Yonas Tesfay Gebrekiros

Analysis of Integrated Balancing Markets in Northern Europe under Different Market Design Options

Doctoral thesis

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Norwegian University of
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Thesis for the degree of
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In loving memory of my little brother, Agazi.

Summary

In an electric power system, the instantaneous balance between demand and supply must always be maintained. Due to the inherent stochasticity of certain types of generation sources and demand, as well as contingencies in the power system, imbalances occur. Hence, corrective actions are required to continuously keep the system in a balanced state. For this, the system needs reserve generation capacity with a set of desired technical characteristics such as fast ramp up speed and short startup time. By making use of market mechanisms, the System Operator ensures the availability of enough reserve capacity ahead of time and activates the resources in response to system imbalances in real-time in a setting called balancing market.

An integrated European electricity market is expected to increase the efficiency, overall welfare, competition, and security of supply. With this understanding, the day-ahead market in Europe has undergone integration efforts with the long-term goal of establishing a single European electricity market. Integration of the balancing market is also expected to bring a socio-economic benefit. This is due to the sharing of balancing resources and the reduction of required balancing actions by netting of imbalances in adjacent areas. However, prior to the realization of a fully integrated balancing market, balancing market variables such as gate closure times, remuneration mechanisms, and the contract periods have to be harmonized first. This PhD work assumes that these variables are in place in the mathematical formulations and the associated results.

The main objective of this thesis is the modeling of integrated reserve procurement and balancing energy markets in a setting similar to the current sequential market clearance order in Europe. The models are used to analyze the impact of balancing market integration in the current European electricity market settings and allow the comparison of different market designs. To assess the impact of balancing market integration, optimization models addressing cross-border reserve procurement and balancing energy market integration are developed. The first one is composed of three interdependent blocks: Reserve bidding price determination, reserve procurement, and day-ahead market clearance. The other one is a formulation for balancing energy market. In addition, a methodology for optimal cross-border transmission capacity allocation is developed. The balancing market integration is implemented in both NTC based and flow-based market coupling settings.

The following are some of the main results obtained in this PhD work:

- Unit based upward and downward bidding prices for reserve provision are a function of the difference between the spot price forecasts and a unit's marginal cost.

- The total reserve procurement cost decreases with increased share of reserved Net Transfer Capacity (NTC), as a result of the possibility of procuring cheaper cross-border reserves. The day-ahead cost generally increases with increase in reserved capacity. However, for small shares of reserved transmission capacity, procuring reserves from another system reduces the need to keep reserves in the expensive system, increasing the flexibility and reducing the day-ahead cost.

- Given the possibility of cross-border reserve procurement, more upward reserve is procured from Norway, Sweden, and the Netherlands. On the other hand, Germany imports some of its FRR requirement.

- Using an NTC based methodology to optimally allocate transmission capacity for FRR exchange for a planning period of 24 hours, a reduction of EUR 26 million ($\approx$ 8 %) in FRR procurement and EUR 53 million in total costs is obtained compared to the base case of no reservation. This result asserts that optimal reservation of NTC for FRR exchange can reduce both FRR procurement costs and day-ahead costs simultaneously.

- For the model with NTC based optimal transmission capacity reservation, where a reservation period of 24 hours has been normally used, sensitivity analyses using a 12 hours reservation period showed very significant cost reductions. This emphasises the importance of short reservation periods for reserve procurement.

- The implicit market clearance option, where the reserve requirement is implicitly considered as a constraint in the day-ahead market clearance, is generally a more efficient market clearance option than the sequential market clearance with optimal transmission capacity reservation. The flexibility due to short planning period and efficiency of the market design option contribute to the significant total cost reduction offered by the implicit market clearance option. The flow-based market coupling with implicit market clearance results in total cost savings of EUR 413 million compared to the case with no transmission capacity reservation. On the other hand, flow-based sequential market clearance with optimal transmission reservation gives a saving of EUR 19 million.

- The possibility of cross-border balancing energy exchange gives cost reduction benefits in comparison to local balancing. The decrease in balancing costs is due to the netting of imbalances and the use of cheaper balancing energy from neighbouring zones. Due to the general improvement in market efficiency, considering the IEEE 30-bus test system, the integrated flow-based balancing energy market clearing results in 20 % lower balancing cost compared to the NTC based approach.

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Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ATC	Available Transfer Capacity
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CEER	Council of European Energy Regulators
CZC	Cross-zonal capacity
DCPF	DC power flow
DCOPF	DC optimal power flow
ENTSO-E	European network of transmission system operators for electricity
EU	European Union
EWEA	European Wind Energy Association
FBMC	Flow-based market coupling
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
FRR-A	Frequency Restoration Reserve - Automatic
FRR-M	Frequency Restoration Reserve - Manual
GCT	Gate closure time
HVAC	High voltage AC
HVDC	High voltage DC
IEM	Internal electricity market
ITVC	Interim Tight Volume Coupling
MIP	Mixed Integer Programming
MOL	Merit Order List
NC EB	Network Code on Electricity Balancing
NC LFCR	Network Code on Load-Frequency Control and Reserves
NTC	Net Transfer Capacity
OPF	Optimal power flow

PTDF	Power Transfer Distribution Factor
RES	Renewable energy sources
ROR	Run-of-River hydro
RR	Replacement Reserve
TSO	Transmission System Operator
TLC	Tri-Lateral Market Coupling
PTU	Program Time Unit
PV	Photovoltaic
PX	Power Exchange

Chapter 1

Introduction

In our day to day activities, there is hardly anything that does not need electricity to function. It powers almost every industry and household one can think of. In most cases, large power generation sources are located far away from load centers. Hence, power has to be converted and transported to the end users by making use of the grid infrastructure. Many stakeholders, such as power producers, traders, the Power Exchange, and the system operator are involved in different aspects of the power system to ensure that the required power is delivered to its intended destination at the right time. In current power systems, which are mostly deregulated, electricity can be traded like any commodity. Unlike other commodities, however, it is yet to become economically feasible to store on a large scale. Consequently, there should be sufficient reserve capacity in the system that can be deployed fast enough to counteract imbalances in the power system. The system frequency is an indicator of the active power balance in a synchronous system; i.e. an imbalance in the system translates to frequency deviation. Consequently, to keep the system frequency at the nominal operating value, there always has to be an instantaneous balance between demand and supply.

In European power systems, driven by the awareness of environmental impacts, unsustainability of fossil fuel based generation, and motivated by the European Union energy directives, massive renewable energy resources (RES) integration is observed. The trend is expected to continue in the following years. Although the integration of RES is crucial to relieving the fossil fuel dependence, the inherent intermittence and limited predictability as well as controllability of these resources is challenging for power system operation.

Apart from the increasing RES integration, more HVDC interconnectors and offshore super grids are expected to link European countries. Concurrently, a number of successful initiatives in electricity market integration (especially the day-ahead market) have been observed paving the way for an integrated European electricity market, also called the internal electricity market (IEM).

Once integration in the day-ahead market is realized, an integrated balancing market (both for reserve procurement and balancing energy markets) becomes a natural successor. Currently, there are a few regional integrated balancing markets in Europe. Unlike the integration of day-ahead markets, significant harmonization steps need to be undertaken to achieve a fully integrated balancing market. This thesis assesses the implications of integrated balancing markets by proposing mathematical models that follow the current market clearance sequence in Northern Europe while assuming that sufficient harmonization is in place.

1.1 Scope

The main objective of this PhD work is to analyze the impact of cross-border balancing market integration. To achieve this, a sequential electricity market model that resembles the current electricity market clearance sequence is developed. The issues of cross-border exchange of reserves, transmission capacity allocation for reserves exchange, and cross-border balancing energy exchange are assessed. Extensive case studies are performed for the North European power system (Nordic, Germany, and Netherlands). The detailed scope of the thesis is presented as follows.

- Developing a market model where the reserve procurement phase is undertaken prior to the day-ahead dispatch for the period reserves are contracted. This is important as simultaneous clearance of the day-ahead market with reserve procurement, which is theoretically more favorable, is not the current market clearance trend in Europe.

- In the European electricity market context, given the possibility of cross-border reserve exchange, some transmission capacity should be set aside for this purpose. As a result, the work develops a model to optimally allocate cross-border transmission capacity for reserves exchange before the day-ahead market clearance.

- Another focus of the PhD work is to develop a mathematical model for a balancing energy market with a possibility of cross-border exchange using transmission capacity already allocated for reserves exchange in the reserve procurement phase.

Flow-based market coupling (FBMC) gives better representation of the physical characteristics of the grid compared to Net Transfer Capacity (NTC) based representation. This, among others, offers more transmission capacity to the market which in turn increases the total social welfare. The EU Guideline for Capacity Allocation and Congestion Management [1] requires FBMC as the preferred method. FBMC is presently used in the Central Western European (CWE) market coupling and there is an ongoing work to prepare for the methodology in the Nordic system [2,3]. Cognizant of this trend, the work also tackles the issue of balancing markets integration in the context of a flow-based mathematical model. This is preceded by adoption of a methodology to aggregate the detailed nodal system representation to a zonal approximation.

1.2 Main contributions

The EU Guidelines and ENTSO-E Network Codes require integration of the balancing markets in the coming years. Even though the net turn over of balancing market accounts for a small percentage of the total, it is believed that the integration of this market increases the socio-economic benefit, nonetheless. A number of research works have asserted this very fact. The thesis contributes to this discussion by developing electricity market models that follow the market clearance hierarchy in Northern Europe. The main contributions are presented as follows:

- Mathematical modeling of sequential electricity market clearance as presently implemented in most European markets. It consists of three interdependent optimization blocks; reserve bidding price determination, reserve procurement, and day-ahead market clearance.

- Development of a methodology to optimally allocate cross-border transmission capacity for reserves exchange.

- Mathematical formulation for a balancing energy market with a possibility of cross-border exchange using transmission capacity allocated for reserve exchange.

- Development of mathematical models for reserve procurement and real-time energy balancing market, discussed above, applying Net Transfer Capacity (NTC) based as well as flow-based formulations.

1.3 List of publications

The main findings of the research work are presented as a collection of the following publications.

I **Y. Gebrekiros**, G. Doorman, S. Jaehnert, and H. Farahmand, *Bidding in the Frequency Restoration Reserves (FRR) market for a Hydropower Unit*, 4th IEEE/PES Innovative Smart Grid Technologies Europe (ISGT EUROPE) conference, Copenhagen, Denmark, 6-9 October 2013.

II **Y. Gebrekiros**, G. Doorman, S. Jaehnert, and H. Farahmand, *Reserve Procurement and Transmission Capacity Reservation in the Northern European Power Market*, International Journal of Electrical Power and Energy Systems (IJEPES), vol. 67, pp. 546–559, May 2015.

III **Y. Gebrekiros**, and G. Doorman, *Optimal Transmission Capacity Allocation for Cross-border Exchange of Frequency Restoration Reserves (FRR)*, 18th Power Systems Computation Conference, Wroclaw, Poland, 18-22 August 2014.

IV Y. Gebrekiros, S. Jaehnert, and G. Doorman, *Sensitivity Analysis of Optimal Transmission Capacity Reservation for Cross-border Exchange of Reserve Capacity in Northern Europe*, 11th International Conference on the European Energy Market (EEM), Krakow, Poland, 28-30 May 2014.

V Y. Gebrekiros, G. Doorman, A. Helseth, and T. Preda, *Assessment of PTDF Based Power System Aggregation Schemes*, 2015 Electrical Power and Energy Conference (EPEC), London, ON, Canada, October 26-28, 2015.

VI Y. Gebrekiros, G. Doorman, S. Jaehnert, and H. Farahmand, *Balancing Energy Market Integration Considering Grid Constraints*, PowerTech conference, Eindhoven, Netherlands, 29 June-2 July, 2015.

VII Y. Gebrekiros, S. Jaehnert, and G. Doorman, *Flow-Based Optimal Transmission Capacity Allocation for Cross-border Reserves Exchange*, Submitted to IEEE Transactions on Power Systems.

The research work also resulted in the following additional publications, that are not included in the thesis.

VIII Y. Gebrekiros, H. Farahmand, and G. Doorman, *Impact of reserve market integration on the value of the North Sea offshore grid alternatives*, 9th International Conference on the European Energy Market (EEM), Florence, Italy, 10-12 May 2012.

IX Y. Gebrekiros, G. Doorman, H. Farahmand, and S. Jaehnert, *Benefits of cross-border reserve procurement based on pre-allocation of transmission capacity*, PowerTech conference, Grenoble, France 16-20 June 2013.

X Y. Gebrekiros and G. Doorman, *Balancing Energy Market Integration in Northern Europe - Modeling and Case Study*, IEEE Power and Energy Society General Meeting, Washington DC, USA, 27-31 July 2014.

XI Y. Gebrekiros, G. Doorman, and S. Jaehnert, *DCOPF based Optimal Transmission Capacity Reservation for FRR Exchange using Implicit and Sequential Market Clearance*, 12th International Conference on the European Energy Market (EEM), Lisbon, Portugal, 20-22 May 2015.

1.4 Organization of the thesis

This thesis is presented as a collection of the main publications produced in the course of the PhD program which are provided in the **Appendix**. The remainder of the thesis is organized as follows:

Chapter 2 presents the background for the research work by narrowing down the discussion from the overall electricity market to the balancing market. It reviews relevant literature, compares results from research works bearing relevance to the context of the thesis, and discusses current European regulations, initiatives, and recommendations on balancing markets.

Chapter 3 briefly discusses the models developed in this thesis and summarizes the methodologies, assumptions, case studies, and the main results extracted from the publications that make up the thesis.

The main conclusions and recommendations for future work are presented in **Chapter 4**.

Chapter 2

Background

2.1 The power system

An electric power system is a network of electrical components composed of power generation plants and consumers of electric power connected by the transmission and distribution networks.

2.1.1 Generation

In many cases, a generation plant contains one or more generators that convert mechanical energy to electrical energy, with some exceptions to this principle being generation from photovoltaic (PV) and battery storage. Generation plants can use nuclear fuel; burn fossil fuels such as coal, oil, and gas; employ hydropower; or use renewable energy sources such as wind, solar, and biomass to generate electric power.

To generate electric power in a cost effective way, power plants are usually scheduled according to their marginal costs; i.e. units with low marginal costs (base load units) operate most of the time and units with higher marginal costs, often characterized by higher marginal cost and low startup time, are scheduled for operation during peak-load hours. Wind, PV, and other variable renewable energy source (RES) power plants have very low operating costs, which is usually considered to be zero, and available power from these sources is always used as much as possible.

According to the response speed and controllability of their output, three types of generating units can be identified.

- Some units based on nuclear and lignite coal have long startup times and only supply base load with no need to change their generation set point. Such units are called base-load units.

- In a power system, the instantaneous balance between supply and consumption (demand summed with network losses) should be met. The power output from RES such as wind, run-of-river hydro, and PV is usually intermittent and uncertain, thereby creating imbalances in the system. Such generating units are called non-dispatchable units.

- To ensure that the instantaneous balance between power generation and consumption is sustained, the system operator should guarantee the availability of generating units that can start up and change their output fast. The response makes such units instrumental to counteract system imbalances. Units based on storable hydro, gas, oil, and hard coal units fall in this category and are called regulating units.

2.1.2 Transmission and distribution system

Bulk power is normally transferred using high voltage AC (HVAC) transmission system via a step up transformer from a remote generating station to the distribution system. However, there are instances where HVDC transmission is preferred to HVAC as in connecting two synchronous systems, transmitting large amount of power over long distances, and long distance sub sea transmission. The distribution system represents the final stage in the transfer of power to the individual customers. Small industrial customers are directly connected to the primary feeders, where as residential and commercial customers are supplied by the secondary feeders [4]. Today's power systems often have embedded generation or co-generation plants connected at various distribution system nodes.

2.1.3 Power system loads

The final destination of the power generated by the generators is to be consumed by the loads to perform a certain task. Power system loads range from heavy industrial consumers to small household appliances. In some cases, the electrical loads contribute to the stable operation of the system by committing to adjust their consumption in response to system imbalances (*cf.* [5] for the case in Norway).

2.2 Power system security

For reliable service, a power system should be designed and operated in such a way that most probable contingencies can be sustained without loss of load and the most adverse contingencies possible do not result in uncontrolled, widespread and cascading blackouts [4]. A power system is designed in such a way that its stability is maintained in the event of loss of major component (transmission line, generator etc). This is described as the N-1 criterion. In the Network Code on Operational Security [6], ETNSO-E defines operational security as "*…Transmission System capability to retain a Normal State or to return to a Normal State as soon and as close as possible, and is characterized by thermal limits, voltage constraints, short-circuit current, frequency limits and stability limits*". The network code further elaborates on the frequency control that each TSO should operate with sufficient upward and downward active power reserves to counteract imbalances. Moreover, the TSO shall ensure the activation of active power reserves at different time scales to correct frequency and power exchange errors.

2.3 RES integration in the power system

With population increase and emergence of new middle class, the global energy consumption has increased rapidly. This is manifested in the consumption of massive fossil fuel based energy sources (for electricity generation or other forms) that pollute the environment as a result of increased emissions of anthropogenic green house gases (GHG). The integration of RES is an important intervention in relieving the dependence on fossil fuel based power generation.

Twidell et al. [7] define renewable energy as "*... energy obtained from naturally repetitive and persistent flows of energy occurring in the local environment*". For electricity applications, power plants based on hydro, solar (either PV or Concentrated Solar Power), wind power, tidal power, biomass power, and geothermal power are some of the examples.

In 2012, 19 % of the global energy consumption[1] was obtained from RES, 5.8 % of which was provided by power from hydro, wind, solar, geothermal, and biofuels [8]. Focusing on wind power, more than 35 GW was added in 2013 raising the total installed capacity to 318 GW globally. According to the European Wind Energy Association (EWEA), there was about 129 GW of installed wind power capacity (121 GW on shore and 8 GW offshore) across the European Union (EU) by the end of 2014, accounting for 14 % of the generation mix [9]. By the end of 2014, the installed solar photovoltaic (PV) capacity in the EU reached nearly 87 GW with Germany topping the list at about 38 GW and Italy following at 18.5 GW [10]. The trend of annual RES installations in relation to total annual installed generation capacity in the EU is illustrated in Fig. 2.1.

2.3.1 Energy directives affecting RES integration in the EU

By setting future targets, the EU is fostering the RES integration into the power system. One of these targets is the climate and energy package called "20-20-20" target. To prevent climate change from reaching catastrophic levels this century, and to decrease dependence on imports of foreign oil and gas, this EU's climate change and energy policy sets the following targets for 2020 [11]:

- Cutting greenhouse gases by at least 20 % of 1990 levels.
- Cutting energy consumption by 20 % of projected 2020 levels, by improving energy efficiency.
- Increasing use of renewables to 20 % of total energy production.

[1]Traditional biomass accounted for 9 % renewable energy consumption and 4.2 % was the share covered by heat energy from modern RES.

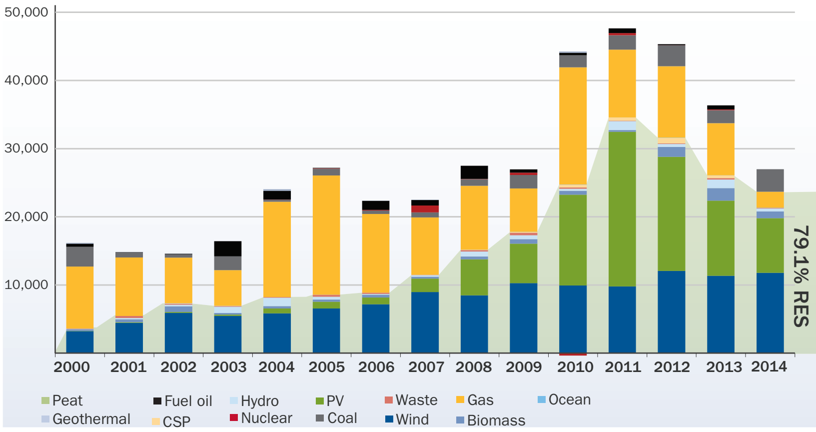


Figure 2.1: Annual RES installed capacity in relation to total annual installed generation capacity [9]

Furthermore, to keep the average temperature change below 2 $°C$, the European Council confirmed, in 2011, the EU objective of reducing greenhouse gas emissions by 80-95 % by 2050 compared to 1990, inline with the position endorsed by world leaders in the Copenhagen and the Cancun Agreements [12].

2.3.2 System impacts of RES integration

RES, apart from storable hydro, are generally intermittent and characterized by limited predictability and controllability. As a result, massive RES penetration has a huge impact on the power system. System impacts of wind energy are categorized as short-term and long-term[2] in [13]. Additional reserve requirements and increased cost of system balancing, which occur due to the fluctuation in wind power output, are among the short term impacts. Other short term impacts include amount of fuel used and the corresponding emissions, stability of the transmission system, transmission and distribution losses. Long-term, the expected wind power production during peak load hours, i.e. the ability of wind power to replace conventional capacity, has an impact on the power system adequacy. From the system balancing point of view, increase in RES integration increases the need for more balancing resources in the system. The impact of RES integration on reserve requirements is discussed in Section 2.7.1 B.

[2]Short-term impacts are in the operational time scale in the range of minutes to hours where as long-term impacts are the impacts on long-term transmission planning and generation capacity adequacy.

2.4 Electricity markets

Electricity market is a general name which refers to many constituent markets such as forward, day-ahead, intra-day, balancing, and ancillary markets. In a restructured power system, electricity market refers to a platform where sales and purchases, through offers to sell and through bids to buy respectively, of electric power and energy is performed. In a typical electricity market, several entities like producers, consumers, traders or brokers take an active role in the market process. In an efficient electricity market, all participants should have equal access to the market and to all relevant information about prices and supply conditions [14]. The rules and practical arrangements governing how the different entities operate is called market design.

2.4.1 Deregulation/Restructuring of the electricity industry

Historically, the electricity industry has been characterized by economies of scale in the generation and necessity of an extensive transmission and distribution network which were integrated within individual electric utilities [15]. However, in the mid-1980s several countries realized that the natural monopolistic characteristics of electricity supply and generation were considered less important compared to other factors; thus, they had to become potentially competitive. As a consequence, it was noted that a separation of network activities from generation and supply and the introduction of competition to the potentially competitive parts of the industry might increase the overall efficiency. A summary of the background for deregulation in the electricity sector in many parts of the world is presented in [16]. Variation of investment cost of similar generating unit across utilities, operating cost of generating units, employment practices and wages, pricing inefficiencies, and abated innovation in a vertically integrated system are pointed out as the main drivers.

Deregulation or restructuring[3] are the terms used for the reorganization of the vertically integrated power supply industry which started in the early 1990s in many countries. In a vertically integrated structure, one utility handles the functions of generation, transmission and distribution within a certain geographical area. Restructuring of the power supply system includes unbundling of the system into a competitive part comprising generation and retail, as well as a monopolistic part comprising transmission and distribution. Discussion of the electricity industry begins with the recognition of three distinct components: generation, transmission, and distribution plus retail [17]. In Europe, England and Wales were the pioneers of restructuring with the Electricity Act of 1989. Norway followed with the Energy Act of 1990 and the other Scandinavian countries and Finland joined this market during the 1990s [14].

[3]The term deregulation is most relevant in cases where the industry was privately owned and under public regulation which was typical for the USA. In those cases public regulation could be phased out for part of the system. In other cases, for instance where public ownership prevailed, restructuring is a more suitable term for this process [14].

2.4.2 Electricity markets in Europe

Power systems in different corners of the world have different electricity market structures. It can be generalized, however, that electricity trade starts quite long before the actual delivery. In competitive power markets, assuming perfect competition, the wholesale price is determined by the generation costs of the marginal technology, i.e. the short run marginal costs (SRMC) of the most expensive plant needed to meet demand. Consequently, risks emerge for market participants on either side of the market due to the high volatility and occasional spikes in the electricity spot prices. Long-term contracts like futures or forwards allow for management of the price risk by effectively locking in a fixed price and therefore avoiding uncertain future spot prices [18]. The authors also argue that forward markets price formation in European Energy Exchange (EEX) is influenced by historic spot market prices.

A day before the actual delivery, the day-ahead market clears where prices are determined according to the demand and supply bids. In the Nordic and Baltic regions, Elspot is the arena for trading energy in the day-ahead market [19]. Every morning members send their bids to the Elspot trading system for the next day. Each bid specifies the volume in MWh/h that a member is willing to buy or sell at specific price levels (EUR/MWh) for each individual hour in the following day. After the deadline for submitting bids (12:00 CET), Elspot feeds the information into a specialist computer system which calculates the price, and prices are announced, and from 00:00 CET the next day, energy is physically delivered hour for hour.

For any incidents that take place after the gate closure of the day-ahead market, market participants can adjust their portfolio in the intra-day market. The deadline for changes, gate closure in the intra-day market, can be up to one hour (or in some cases 30 or 15 minutes) before energy delivery. Elbas is an intra-day market for trading power operated by Nord Pool Spot and covering the Nordic region, Baltic region as well as Germany and recently the UK [19]. At 14:00 CET, capacities available for Elbas trading are published and trading takes place every day around the clock until one hour before delivery.

Typically, before the day-ahead market is the reserve procurement market where the TSO procures reserves for a given period of time to secure availability of resources during real-time balancing. To counteract the imbalances during real-time, the TSO activates (or asks for the activation of) the cheapest balancing resources in the balancing energy market. The reserve and balancing energy market are discussed in detail in Section 2.7. A typical sequence of electricity markets in Europe is shown in Fig. 2.2.

2.5 Electricity market integration

Historically, electricity markets were limited to one or multiple TSO control areas which often are bounded to national borders. Initially, the cross-border intercon-

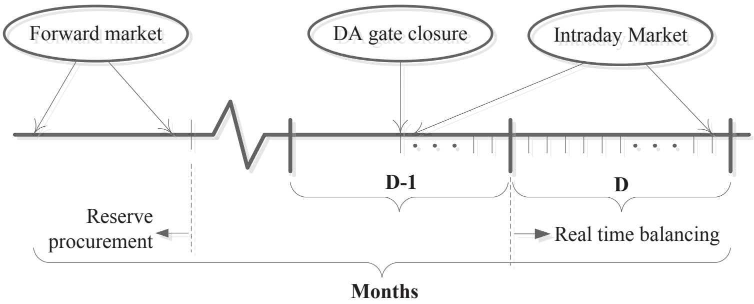


Figure 2.2: Typical electricity market chronology in Europe [20]

nectors were constructed for the purpose of improving the stability of the electricity system and to enable mutual support between countries. After liberalization, they are regarded as a means to foster international trade and to link markets which otherwise have too little competition [21]. The integration of electricity markets can bring about major efficiency gains in social welfare by utilizing generation capacity more efficiently and, thus, reducing the necessity of large idle generation capacity [22]. Depending on the market design and level of electricity market integration, the transmission capacity is auctioned either explicitly or implicitly.

2.5.1 Explicit transmission capacity auction

Explicit transmission capacity auction refers to an arrangement where transmission capacity is auctioned to the market separately and before the day-ahead market clearance. It is a method of handling the capacity on cross-border interconnectors where the capacity is normally auctioned in portions through annual, monthly and daily auctions [23]. When parties are not able to predict prices in the connected regions, results sometimes show adverse flows, where a flow from a high price area to a low price area occurs. Lack of information due to separate auctions for energy and transmission capacity can result in an inefficient utilization of interconnectors resulting in decrease of social welfare, less price convergence, and adverse flows [24].

2.5.2 Implicit transmission capacity auctions

With implicit transmission capacity auction, the auctioning of the transmission capacity is implicitly included in the electricity market auctioning thus shielding market parties from the adversities of price predictions[4]. Implicit auctions ensure that flow is from the surplus area to the deficit area. This results in economical utilization of transmission capacity as it avoids the inefficiencies of the explicit transmission capacity auctions, and it generally eases the complexity of electricity trading. Implicit transmission capacity auction is the basis used for market splitting and market coupling.

[4]It should be noted that market parties still need to make predictions for planning purposes.

A Market splitting

When the implicit capacity auctions are held within the domain of a single Power Exchange (PX), it is referred to as market splitting [24]. When the transmission capacity between the bidding areas is not enough to give price convergence, this results in different prices referred to as area prices.

B Market coupling

Electricity market coupling refers to the implicit auctioning of cross-border physical transmission rights via the hourly auctions for electric energy organized by PXs a day ahead of delivery with the objective of simplifying cross-border trade [23, 25]. It is common to differentiate between price coupling and volume coupling.

B.1 Price coupling In this type of market coupling, the involved PXs forward all their market data and market rules to the market coupling algorithm which centrally computes the prices and flows and forwards them to the corresponding PXs.

B.2 Volume coupling This uses the same input data as the price coupling algorithm. However, the PXs only consider the flows and calculate the prices in a second step. Depending on how loosely or tightly the coupling algorithm follows the market rules, one gets loose volume coupling or tight volume coupling [26].

2.6 Electricity market coupling: History and trends in Europe

The European electricity market has been subjected to integration efforts with the long-term goal of establishing a single electricity market; alternatively called the internal electricity market (IEM) [23]. In the following subsections, the market integration trends in Europe will be discussed in detail. Depending on how the grid constraints are considered in the market coupling algorithm, we identify Net Transfer Capacity (NTC) based and flow-based market coupling (FBMC) in Europe[5].

2.6.1 NTC based market coupling

Prior to discussing NTC based market coupling, it is important to understand the definition and calculation of NTCs[6]. The Total Transfer Capacity (TTC) refers to the maximum exchange programme between two areas compatible with operational security standards stated in each TSO's grid code. To cope with the uncertainties on the computed TTC values, a security margin called Transmission

[5]Nodal pricing, for example in the PJM market [27], makes use of detailed grid representation. However, this is not practiced in Europe and is outside the scope of this thesis.

[6]Proposed by European Transmission System Operators(ETSO) [28], a predecessor to ENTSO-E, the definition and discussions are still governing.

Reliability Margin (TRM) is introduced. As a result, the NTC is the maximum exchange programme between two areas which can be offered to the market without affecting system security and taking into account the technical uncertainties, i.e. $NTC = TTC - TRM$ [28]. In an NTC based market coupling, therefore, cross-border capacity (NTC in this case) is allocated implicitly within the auctioning of energy in the interconnected electricity markets disregarding the physical laws governing power flow.

A communication from the European Commission sets an internal electricity market (IEM) for Europe as a prerequisite to achieve the objectives of the Union policy on energy[7] [29]. Between 2006 and 2010, the Tri-Lateral Market Coupling (TLC), integrated the French, Belgium and Dutch day-ahead markets [30]. The TLC was initiated by the TSOs and PXs of the respective countries. Following the TLC, the CWE coupling, an initiative launched in 2010 and covering the Netherlands, Belgium, France, Germany and Luxembourg, created a single platform for day-ahead electricity trading [31]. This was followed by the Interim Tight Volume Coupling (ITVC) which increased the efficiency of the European power system by coupling the day-ahead market of the CWE region with the Nordic market. The most recent one is the Price Coupling of Regions (PCR), which has been in operation since May 2014 [32]. The project is an initiative of seven PXs: APX, Belpex, EPEX SPOT, GME, Nord Pool Spot, OMIE and OTE, covering the electricity markets in Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Slovenia, Sweden, and the UK. One of the key objectives of PCR project is the development of a single price coupling algorithm, Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA) which will be applied to calculate energy allocation and electricity prices across Europe, maximizing the overall welfare and increasing the transparency of the computation of prices and flows.

2.6.2 Flow-based market coupling

In the Nordic system, the respective TSOs determine all capacities between price areas and communicate these capacities to Nord Pool Spot, who will enter these values as constraints into their market splitting algorithm. In this system, NTC based allocation gives reasonable results as interdependencies are low and market flows will not differ significantly from physical flows. In the highly meshed Central European system there is no market splitting and each country is considered a single price area regardless of internal congestions. Thus, NTC based allocation has serious shortcomings in such instances. Because physical flows follow the transmission path of least resistance, power exchanges both within and between bidding areas (or countries) will result in loop flows that may lead to significant unplanned cross-

[7] Set out in Article 194 of the Treaty on the Functioning of the European Union, the objectives of the Union policy include: secure and competitively priced supplies; renewables and climate change targets of 2020 and beyond; and significant increase in energy efficiency across the whole economy.

border flows [33,34]. For instance, a single transaction between Germany and France will partly flow directly between the two countries but also through the Netherlands-Belgium-France, Switzerland-France, and Switzerland-Italy-France corridors. Thus, a model based on NTC tends to be ineffective in highly meshed power networks since the physical reality is not accounted for [35].

The EU Guidelines on Capacity Allocation and Congestion Management (CACM[8] [1]) require a shift from the current NTC based market integration approach to flow-based market coupling (FBMC) [36–38] to increase the overall electricity market efficiency. FBMC makes use of power transfer distribution factors (PTDF) and is based on DCOPF: but, instead of modeling the whole grid, only interconnections and so called Critical Network Elements (CNE) are considered. It is a linear approximation of the physical reality, albeit much better than the NTC approach. A PTDF refers to the line flow sensitivity for given transaction between two nodes.

Flow-based algorithms are expected to improve quality of results and increase the social welfare compared to NTC based calculations as they better represent the physics of power flow. This results in better utilisation of the physical infrastructure within the FBMC region, which leads to an increased trading volume when compared to NTC based auctions [35] (*cf.* Fig. 2.3). However, their ability to improve total welfare heavily depends on the quality of grid models [23].

During the 2010 CWE FB experimentation [39], it was proven that the Enhanced FB capacity calculation is feasible from an operational point of view. It was also demonstrated that it increases the proposed capacity offered to the market compared to NTC in addition to addressing the transparency requirements and concerns on market players understanding. The flow-based methodology has been used on a daily basis in the CWE day-ahead market coupling process since 20 May 2015 [2].

2.7 Balancing markets

A balancing market is an institutional arrangement providing market-based balance management consisting of three design pillars namely balance planning, balancing service provision, and imbalance settlement [40]. In the literature, balancing market is sometimes used as a term for the balancing energy market (*cf.* Section 2.7.3). In this thesis, the term balancing market is a collective term for the reserve procurement market and balancing energy markets. Both reserve procurement and balancing energy markets are discussed in the following subsections.

[8]These Guidelines deal with the integration, coordination and harmonisation of the congestion management regimes, to the extent that such harmonisation is necessary in order to facilitate electricity trade within the EU.

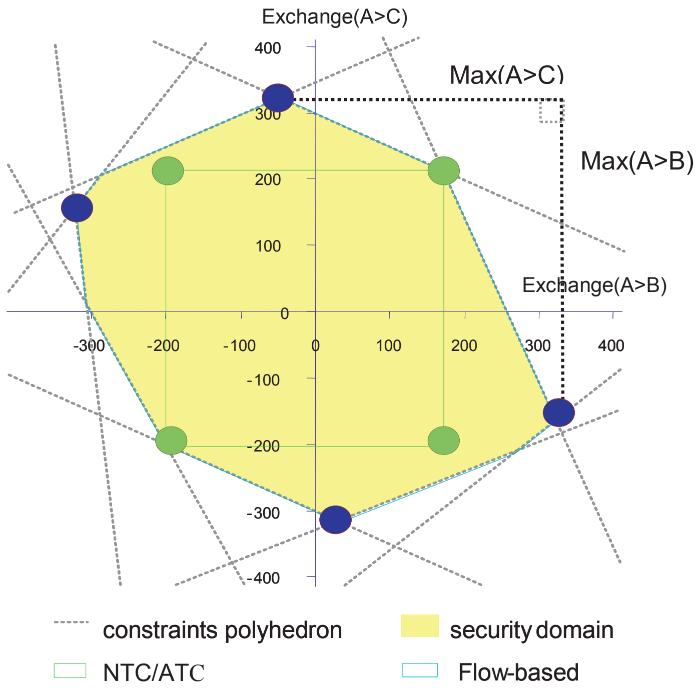


Figure 2.3: Security of Supply domains for FB and NTC based MC [39]. Max (A→C) blue dot can not occur at the same time as Max (A→B) as the combination of the two values is outside of the security domain. The NTC values (green dots) are simultaneous values that limit the bilateral exchanges between the bidding areas whose choices are made by the TSO inside the security domain.

2.7.1 Reserve procurement market

The TSOs procure reserve capacity in order to avoid the risk of insufficient offers for balancing energy in real time. As a result, the TSOs hedge this uncertainty by securing, in advance, a sufficient amount of capacity available in their control area [33]. In liberalized European electricity markets, reserve adequacy is ensured through appropriate institutional mechanisms. Typically, TSOs procure reserve capacity from Balancing Service Providers (BSPs) to guarantee the availability of sufficient reserve for real-time operation through either mandatory impositions, bilateral contracts, or auctions [41]. BSPs are mostly producers whose generation resources are contracted by the TSO for balancing purposes (*cf.* Section 2.7.2 B).

A Types of reserves and activation

To keep the system frequency at the nominal operating value, the instantaneous balance between demand and supply should be sustained. As large scale electrical energy storage in the transmission system is economically infeasible, there is a need to keep reserve capacity to counteract imbalances. ENTSO-E defines three types of operating reserves[9] [42–44].

A.1 Frequency Containment Reserves (FCR) are operating reserves deployed between 2-20 seconds to counteract frequency change due to sudden imbalance in the system. These reserves are also known as primary control reserves in the Central European system and frequency controlled reserves normal (FCR-N) and frequency controlled disturbance reserves (FCR-D) in the Nordic system [20]. For the Nordic system 600 MW of FCR-N is constantly allocated for regulation in the normal state. Similarly, 1200 MW of FCR-D, corresponding to the single largest disturbance in the system reduced by 200 MW of self regulation, is jointly kept in the system.

A.2 Frequency Restoration Reserves (FRR) are operating reserves activated to restore the system frequency to nominal value and are deployed to replace the FCR. These reserves are activated within a period of 30 seconds to 15 minutes. There exist automatic and manual components of the FRR termed FRR-A and FRR-M respectively.

A.3 Replacement Reserves (RR) These reserves are used to release already activated FCR and FRR. They are manually activated and called tertiary reserves in the Central European system but are not available in the Nordic system.

The control actions taken and the system frequency behaviour in the event of a typical fault is shown in Fig. 2.4.

B Reserve requirement

The Network Code on Load-Frequency Control and Reserves (NC LFCR) defines minimum requirements for FRR and RR dimensioning based on a combination of a deterministic and probabilistic approach and coherent with the quality requirements [6, 45]. It specifies that the minimum values for FRR and RR required for Central Europe and Nordic shall be based on a combination of:

- A deterministic assessment based on the positive and negative dimensioning incident[10], i.e. the FRR Capacity shall not be smaller than the dimensioning incident (separate for positive and negative direction).
- A probabilistic assessment of historical records for at least one full year. In this case, a minimum value for the sum of FRR and RR capacities is defined by the 99 % quantile of the load frequency control block imbalances (separate for positive and negative direction).

[9] The definitions are specific for the European power systems.

[10] The dimensioning incident is defined as the maximum expected instantaneous power deviation between generation and demand in a control area [46].

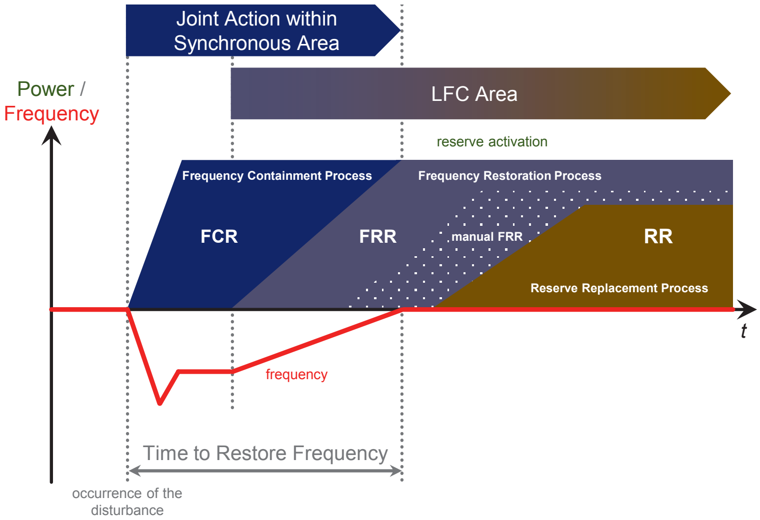


Figure 2.4: Dynamic hierarchy of Load-Frequency Control processes [45]

Future power systems will incorporate massive RES integration. This increase in RES capacity in the system will increase the volume of imbalances due to the limited predictability of these resources. Consequently, studies suggest that increased RES integration, increases the required volume of reserve capacity. Vos et al. [47] summarize literature on methodologies followed to determine the impact of wind power on reserve requirements and list them as: heuristic (based on contingency analysis), probabilistic (based on combining the probability density curves of all three imbalance drivers namely demand variations, unexpected power plant outages and RES variability), and system simulation approaches (Unit Commitment based system cost calculation). Accordingly, they apply a probabilistic method to analyze the impact of increased wind production on reserve requirement within the Belgian power system. Similarly, based on the data for Finland, Holttinen et al. [48] suggest a linear relationship between wind penetration and increased reserve capacity as a percentage of installed wind capacity, resulting in a 7 % increase of reserve[11] for 20 % wind penetration. The same study suggests an 8 % increase in reserve requirement for 15 % wind penetration in Germany. Table 2.1 shows the increased reserve requirement for 2030 in each country based on the wind power penetration and the data in [48].

2.7.2 Parties in balancing markets

Three main entities, described in the next paragraphs, take part in balancing markets. The interactions between these parties is illustrated in Fig. 2.5.

[11] Increase in reserve requirement expressed in percentage of wind capacity

Table 2.1: Estimated increase in reserve requirements (MW) based on wind penetration in the Northern Europe [41]

	Wind	Wind	Increased Requirement	
	2030 (TWh)	2010 (TWh)	Up (MW)	Down (MW)
Norway	19	1	270	270
Sweden	23	1	513	513
Denmark	22	7	829	829
Finland	7	1	84	84
Germany	139	32	4385	4385

A Balancing Responsible Parties (BRP)

All electricity market participants interact with the market through a BRP, or are a BRP themselves [49]. Before the hour of operation, each BRP has a market position or balance, consisting of the sum of all its obligations in the form of sales and purchases in organized markets like day-ahead and intra-day, and through bilateral transactions. The balance is defined for each Program Time Unit (PTU), which typically can be 15, 30 or 60 minutes. The BRPs are responsible for their net balance over the whole PTU, where as the TSO is responsible for balancing within the PTU, as well as the transition between one PTU to the next [50].

B Balancing Service Providers (BSP)

In an unbundled system, a TSO does not own generation or consumption resources. As a result, the TSO will be in lack of resources to compensate for the aggregate deviations of the BRPs[12]. Hence, the TSO uses the resources of BSPs to balance the system. BSPs are usually producers with generation resources and sometimes specific consumers can also contribute [51].

C Transmission System Operator (TSO)

The TSO plays a central role in the balancing market: 1) by procuring reserves for balancing from BSPs to guarantee sufficient capacity in real-time operation and 2) by addressing real-time imbalances with least cost measures and charging the BRPs for their deviations from the scheduled plans [41].

2.7.3 Balancing energy markets

The balancing energy market is the last electricity market on which energy can be traded. It serves to procure energy that corresponds directly to the real-time

[12]Note that from a system point of view the individual imbalances of the BRPs are irrelevant, it is only the net sum of all deviations at the system level that contributes to deviations in the frequency and needs to be compensated.

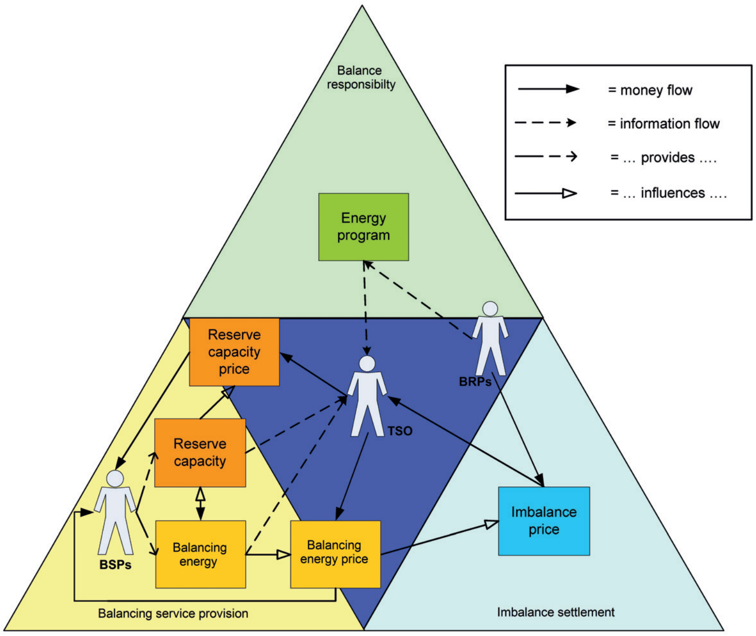


Figure 2.5: Interaction between the parties in a balancing market [50]

adjustment of generation and consumption in order to adjust the system imbalances. In the NC EB [52], an imbalance is defined as *"...an energy volume calculated for a BRP and representing the difference between the allocated volume attributed to that BRP, and the final Position of that BRP and any imbalance adjustment applied to that BRP, within a given imbalance settlement period"*.
Balancing energy can only be provided by generation and consumption resources that are technically capable of providing balancing energy [53]. In general, aggregate deviations over the whole PTU in a given balancing area are balanced by the TSO and charged to the responsible BRPs by means of the imbalance settlement mechanisms. On the other hand, the fluctuations inside the PTU remain the responsibility of the TSO [47]. The balancing energy market in the Northern European system is presented in detail in Section 2.7.5.

2.7.4 Integration of balancing markets in Europe

It can be argued that integrated electricity balancing market is the final step in the creation of a single European electricity market. In 2012, ACER adopted the Framework Guidelines on Electricity Balancing [54], with the aim, "*... to providing a solid framework for the integration of national balancing markets and the achievement of the single European electricity balancing market*". These guidelines focus on increasing cross-border competition in the balancing time frame and on the overall efficiency of balancing the electricity system, while safeguarding the security of supply. Based on the guidelines from ACER, ENTSO-E developed the Network

Code on Electricity Balancing (NC EB) with the purpose of establishing common rules for electricity balancing including the establishment of common principles for procurement and settlement of FCR, FRR, and RR and common methodology for the activation of FRR and RR [52]. Balancing market integration is expected to allow TSOs to more efficiently procure balancing services and avoid simultaneous up and down regulation in adjacent areas promoting efficient and competitive price formation and market liquidity [55]. For the exchange of balancing services between countries, however, an integration of national regulating power markets is necessary. This requires a harmonisation of regulating power market rules [56]. Van der Veen [53] proposes four cross-border balancing arrangements listed in order of their complexity and requirement for harmonization.

- *System imbalance netting* refers to the cancelation of positive and negative imbalances in adjacent areas, preventing opposite balancing energy activation. This arrangement does not require any change in balancing market design.
- *BSP-TSO trading* refers to an arrangement where two or more TSOs work to establish a compatible balancing market [41]. BSPs can place bids in the market area of the neighbouring TSO. For this arrangement, harmonization of the PTU, gate closure times, and balancing service bid are necessary requirements.
- *Additional voluntary pool* is a multinational balancing service market in which TSOs can share part of their balancing resources with other TSOs in a pool. TSOs can use the bids from the pool, and add these to the bid ladder of their own market. This arrangement is also referred to as TSO-TSO trading without common merit order list.
- *Common merit order list* is an arrangement where all bids from the neighbouring TSOs are combined to form a common merit order list. The TSOs pass corresponding bids from their area to a regional TSO, that takes the responsibility of maintaining system balance by activating resources from the common merit order list. This arrangement is also referred to as TSO-TSO trading with common merit order list.

By performing a simultaneous reserve procurement and day-ahead market clearance with implicit allocation of transmission capacity allocation for reserve exchange, Farahmand et al. [57] numerically show that there is a cost reduction benefit of cross-border reserve procurement. Using a case study of the Northern European power system, Jaehnert et al. [58] assert that there is a socio-economic benefit by integrating regulating power markets which results from a provision of reserve capacity from the Nordic to the continental European power system, and reduced activation of reserves due to imbalance netting in the continental power system. Similarly, based on Northern European power system, [40,59] also assert that multinational balancing markets significantly reduce balancing costs.

Considering actual balancing market integration initiatives in the European power market, the Grid Control Cooperation (GCC), where in March 2010 four of the

German TSOs established a common platform for reserve procurement and real-time balancing [60] is one example. As of 2012 GCC expanded to the surrounding control areas forming International GCC (IGCC), where the TSOs of Denmark, the Netherlands, Switzerland, Czech Republic, and Belgium became members. IGCC is an inter-TSO cooperation aimed to prevent counteracting FRR activation in different control blocks by real-time netting of imbalances using the remaining ATC [61]. Similarly, in the Nordic system, a common regulating power market has been in place since 2002. However, the reserve procurement is done separately by each of the Nordic TSOs [62].

2.7.5 Balancing markets in Northern Europe

In the thermal dominated Central European system, it is often necessary to procure reserves and pay for their availability. On the other hand, in the hydro dominated Nordic system, with the exception of periods with high demand and prices, sufficient reserve capacity is available that the market for reserves does not exist [56]. The reserve markets in the Northern European system are discussed in Table 2.2.

In the Nordic system, 300 MW of FRR-A (introduced in 2013, and fully activated in 2 minutes) is maintained in the morning and evening hours in 2015. The country specific requirements are divided in proportion to their annual consumption, which also applies to FCR-N and FCR-D. For the FRR-M, which are fully activated within 15 minutes, each TSO allocates a capacity to cover the dimensioning fault in its own area. In the Netherlands, the FRR-M is only procured for upward regulation purposes and designed to be used only in case of a sudden large generation outage or an outage of an importing HVDC interconnector. In Germany, TSOs procure FRR-M balancing capacity for upward and downward regulation with gate closure for auctions being day-ahead at 10:00h; except for Sundays and Mondays for which balancing capacity is always procured on Fridays. The product resolution in time is four hours [63].

Table 2.2: Balancing markets in Northern Europe [5, 44, 63–66]

	Reserve procurement market			Balancing energy market		
	Contract period	Remuneration	Characteristics	PTU	Characteristics	Remuneration
Norway	Week or season[a]	Marginal pricing (FRR-A and FRR-M)	FRR-M contracted in ROM-season and ROM week. In ROM-season the resolution of bids is the expected winter season. Purchases in ROM week are made based on an assessment of different factors[b].	1 hour (FRR-A & FRR-M)	Only Generators provide FRR-A but Generators and loads provide FRR-M	Marginal pricing
Sweden	1 hour	pay-as-bid (FRR-A and FRR-M)	Bid volume in steps of 5 MW submitted separately for upward and downward FRR-A	1 hour(FRR-A & FRR-M)	Only Generators provide FRR-A but Generators and loads provide FRR-M	Marginal pricing
Denmark-East	1 week (FRR-A)	pay-as-bid FRR-A, Marginal pricing FRR-M		1 hour FRR-M	Generators and loads provide FRR-A and FRR-M	Marginal pricing FRR-M
Denmark-West	1 week (FRR-A)	pay-as-bid FRR-A, Marginal pricing FRR-M	Joint procurement with the German TSOs	1 hour FRR-M	Generators and loads provide FRR-A and FRR-M	Marginal pricing FRR-M
Finland	1 hour	pay-as-bid FRR-A and FRR-M	FRR-A bid volumes submitted in steps of 5 MW	1 hour FRR-M	Generators and loads provide FRR-A and FRR-M	Marginal pricing
Germany	1 week (FRR-A), 4 hours (FRR-M)	pay-as-bid (FRR-A & FRR-M)	FRR-A is jointly procured by all German TSOs. FRR-A balancing capacity and balancing energy are jointly procured.	15 min	The balancing energy volume and price is provided for a whole week for the peak and the off-peak product.	pay-as-bid
Netherlands	1 year tender	pay-as-bid	the procurement of aFRR balancing capacity takes place independently of the procurement of balancing energy.	15 min	Selected BSPs place mandatory bids for balancing energy. Gate closure time is one hour ahead of operation.	marginal pricing

[a] October to April

[b] The factors are, the current energy situation, production forecast, consumption, cross-border exchanges, and probable bottlenecks.

2.8 Transmission capacity reservation for reserves exchange

Electricity trade often starts far ahead of the actual energy delivery and is progressively performed. A typical electricity market chronology in Europe[13] is shown in Fig. 2.2, in section 2.4.2. It can be seen that the reserve procurement takes place some time before the day-ahead market clearance. Besides, the duration for which reserves are contracted is different and is usually longer compared to the resolution of the day-ahead market. As discussed in Section 2.7.1, FRR are currently procured within national borders. However, if there is going to be a possibility of cross-border procurement of FRR, it might be necessary to reserve transmission capacity beforehand to make sure that the reserves are available when needed. One of the risks of transmission capacity reservation in advance is that it is difficult to predict how much of the allocated reserves will actually be called upon at a certain time in real-time risking a valuable transmission capacity going unused [33]. The ACER Framework Guidelines on Electricity Balancing stress that the ENTSO-E NC EB [54] shall forbid TSOs to "*... to reserve cross-border capacity for the purpose of balancing, except for cases where TSOs can demonstrate that such reservation would result in increased overall social welfare and provide a robust evaluation of costs and benefits*". As a result in the NC EB [52], ENTSO-E bestows the right for TSOs to "*... reserve cross zonal capacity (CZC) for the exchange of balancing capacity or sharing of reserves when socio-economic efficiency is proved*". It proposes that the socio-economic benefit is proved in either one of the following:

- *Co-optimisation process* - TSOs bid the actual market value of CZC for the exchange of reserves into auctions of CZC for the exchange of energy in an electricity market in a given time frame.
- *Market-based reservation process* - based on a comparison of the actual market value of CZC for reserves exchange and the forecasted market value of CZC for the exchange of energy. This takes place if no transmission capacity auction in available for the relevant time frame for procurement of reserves [45].
- *Reservation based on economic efficiency analysis* - takes place if it is not possible to calculate any actual market values for both reserves and energy exchange [45]. This is done based on a comparison of the forecasted market value of CZC for the reserves exchange, and the forecasted market value of CZC for exchanges of energy.

With the assumption of only two products (day-ahead energy and reserves) and for a given level of transfer capacity, the optimal allocation of transfer capacity is illustrated in Fig. 2.6 [49]. The main assumption taken here is that transfer capacity has a positive and declining marginal value in all markets.

[13]This figure is intended to specifically show the time sequence of reserve procurement in relation to the DA clearance. Detailed illustrations about the time sequence of electricity market clearance are available in [20, 55].

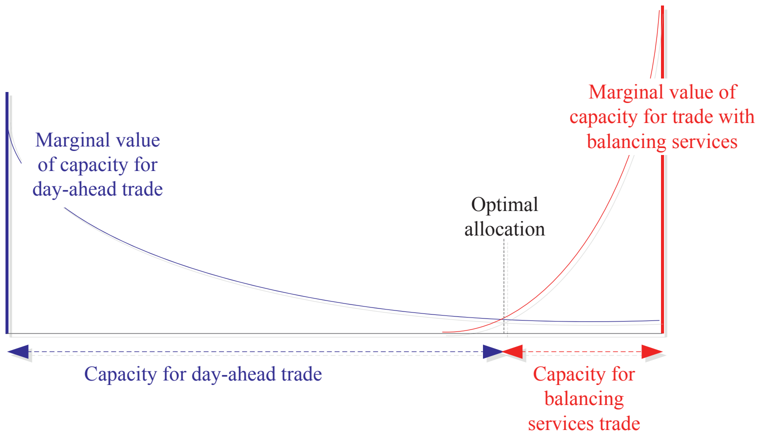


Figure 2.6: A schematic for optimal transfer capacity allocation between two markets [49]

On the issue of transmission capacity reservation for FRR exchange, Jaehnert et al. [60] assert that there is no benefit of pre-reservation of transmission capacity for FRR exchange. They mention that it is sub-optimal in a model where clearing of the spot market is done simultaneously with reservation of reserve and transmission capacity. Besides, this is not the approach in current European electricity markets. By applying a quantitative analysis in Northern Europe, Abbasy et al. [59] show that integrated balancing energy market results in reduction of annual balancing costs by EUR 100 million when enough transmission capacity is reserved. Moreover, by considering the Northern European system in the state of 2030 as a case study, Farahmand et al. [67] assert that a pre-reservation of 100 MW transmission capacity on the Skagerrak HVDC interconnection between Norway and Denmark results in socio-economic loss compared to the dynamic transmission capacity allocation[14].

In the following subsections, practical experiences and case studies regarding transmission capacity reservation for FRR exchange in Northern Europe are presented.

2.8.1 Transmission capacity reservation between Sweden and Germany [33]

By analyzing the average available transmission capacity on all corridors in the CWE region in 2008, a case study undertaken by Sweco Energy Markets[15] [33] determines that for an average of 90 % of the time, the available capacity after the intraday

[14]In this case, the day-ahead market is run by implicitly considering the reserve requirement as an additional constraint where the optimization gives dynamic transmission capacity allocation for reserves exchange, among others. Consequently, pre-reservation of transmission capacity can only increase the costs.

[15]http://www.swecogroup.com/en/Sweco-group/Services/8379/Energy-markets-and-regulation

gate closure exceeds 100 MW.

By making use of historical data, they analysed the impact of transmission capacity reservation for balancing purposes by combining the impacts of reservation on the day-ahead markets and balancing markets. The study considered the impact of reservation of 100 MW on both directions on the Baltic HVDC cable by using 2012 market clearance data and transmission capacity usage and estimated the value of lost trade in the DA market and the impacts on balancing markets. They found that, the loss in the DA market to be around EUR 41 million and gain in balancing market of EUR 80 million, giving a net total gain of EUR 39 million. The EUR 80 million gain in balancing market translates to EUR 62 million in the balancing energy market and EUR 18 million in the reserve procurement market.

2.8.2 Hasle pilot project [68]

The Hasle-pilot was a bilateral project between Statnett and Svenska kraftnät aimed at FRR-A capacity exchange between Norway and Sweden. It was a market based transmission capacity reservation project between October 27, 2014 to December 19, 2014 created to gain experience of transmission capacity reservation. The most important outcome from the Hasle pilot shows that market based capacity reservation is possible and can increase the socio-economic benefit.

- The FRR-A capacity exchange and corresponding reserved cross-zonal capacity (CZC) have been calculated weekly for the upcoming week. Exchange has been decided for three different time blocks per week.
- The socio-economic optimum of the reservation would be reached if CZC is reserved so that the marginal value of using CZC for FRR-A exchange would equal the marginal value of using CZC in the day-ahead market.
- In the pilot, the amount of transmission capacity allocated to the exchange of FRR-A was restricted to exchange a maximum of 50 MW of FRR-A, or 5 % of the forecasted Net Transfer Capacity (NTC), whichever was the lowest.
- To enable exchange of FRR-A capacity from Norway to Sweden, cross zonal capacity between south-western (NO2+NO5) and eastern part of Norway (NO1) has been reserved in addition to the reservation of CZC between Norway (NO1) and Sweden (SE3). This is due to that most Norwegian FRR-A resources are located in the south-western part of Norway.
- The total socio-economic benefit of the FRR-A exchange and transmission capacity reservation between Norway and Sweden for the eight week pilot period was approximately EUR 62000 (just below EUR 8000 per week).
- All the FRR-A exchange in the Hasle pilot has been directed from Norway to Sweden. The Swedish marginal FRR-A price has on average decreased with EUR 4.0 while the Norwegian marginal price has on average increased with EUR 0.9, considering the blocks where FRR-A has been exchanged.

- The socio-economic benefits of the eight week pilot period was more than EUR 20000 higher with daily procurement compared to weekly which is explained as:
  - With a GCT closer to operational hour the uncertainty and thus the risk that FRR-A providers are exposed to will be reduced. It is expected that this will contribute to reductions in the FRR-A prices.
  - A GCT closer to real time make it possible to increase the accuracy of the forecast of the value of transmission capacity in the DAM. This is both with regard to DAM prices and available transmission capacities.

2.8.3 Skagerrak 4 [69]

The Skagerrak 4 is a 700 MW HVDC-VSC cable between Norway and Western Denmark which has been in operation since December 2014. A total of 100 MW of the capacity will be used for delivery of FRR-A from Norway to Western Denmark. Socio-economic evaluation showed positive net-benefits based on price differences in availability payments for secondary reserves between the two countries.

Chapter 3

Methodology, Results and Discussions

The research work addresses two main topics: the reserve market and the balancing energy market. The topics are evaluated using two market coupling approaches. The first one is NTC based and the other one is FBMC. In this chapter, the models developed, summary of the main results, and excerpts of the main publications are presented.

3.1 Model Description

In this section, the scenario descriptions, the models developed, and methodologies followed to address the task of reserve procurement and balancing energy market are discussed. Central for the understanding of the work is the distinction between sequential and implicit market clearance options. In the sequential market clearance option, FRR is procured followed by the day-ahead market clearance. On the other hand, in the implicit market clearance, the day-ahead market is cleared by implicitly considering the reserve requirements as additional constraints to the optimization problem.

3.1.1 Model inputs

The Northern European system, which includes the Nordic region, Germany, and the Netherlands in the state of 2010, is the case study considered for most part of the thesis. In this subsection, we discuss the organization and handling of the input data. The modeling of generating plants, especially the underlying assumptions in aggregating and representing hydropower units is addressed first. Subsequently, the grid representation and the associated input data for NTC and flow-based implementations is discussed.

A Generating units

Based on their response speed and controllability of their output, generation units are classified as base-load units (nuclear and coal plants), regulating units (storable hydro, oil, and gas fired power plants), and non-dispatchable units (wind, run-of-river (ROR) hydro, and PV plants).

A.1 Hydropower units Hydropower accounts for 99 % of the power generation in Norway [70]. It is also quite significant in the whole Nordic system taking around 50 % of the power generation mix. As a result, dealing with electricity market analysis in the Nordic system requires a detailed modeling of the hydropower system. However, modeling of hydropower systems is very challenging and a list of some of the challenges is presented as follows [71]:

- Hydropower systems often have quite complex topologies with up to tens of cascaded reservoirs and power plants in the same river system. The reservoirs may also have different storage capacity with significant water travel time that couples the decisions between several time steps [72];
- There may be different owners for the reservoirs or power stations with the decision of one owner impacting the conditions for the other owners;
- There may be very complicated physical structures in a river system, which represent both non-linear and discrete relationships;
- Uncertainty related to market prices, inflow, and demand;
- Unlike thermal plants, where the fuel price is correlated to the generation cost, the direct cost of hydro is very low. However, the amount of water available is limited and producing now creates an opportunity cost of not using it in a future.

Hence, to account for uncertainties associated with hydropower modeling and obtain solutions that are robust against changing conditions, one should use stochastic models. Hence, long-term hydropower scheduling models such as EMPS[1] are needed. For this work, a simplified and aggregated reservoir representation obtained from the EMPS model is used. The Nordic system, is represented by 49 aggregated reservoirs, with an aggregated hydro unit connected to each reservoir as shown in Fig. 3.1. This level of aggregation is a compromise between expected impractical results due to over aggregation and mathematical complexity of considering individual units. In a given planning period, the marginal cost for hydro units is given by the water value [56]. As there is no significant production cost for hydro power, but rather limited amount of water available, water value refers to the opportunity cost of storing reservoir water for future utilization. These values are dependent on the time of the year and the reservoir level. The water value profile for one reservoir in Norway is shown in Fig. 3.2.

[1]EMPS refers to EFIs Multi-area Power-Market Simulator and is developed by SINTEF Energy Research for long-term hydro power planning [73].

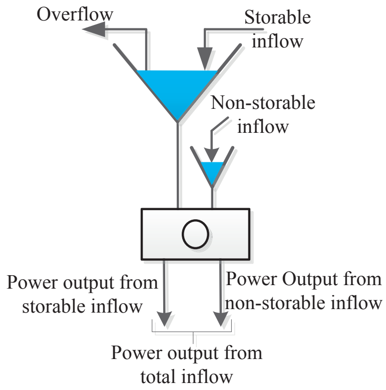


Figure 3.1: Hydro power generation representation

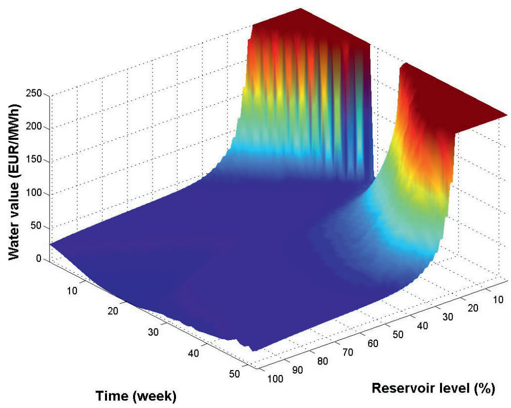
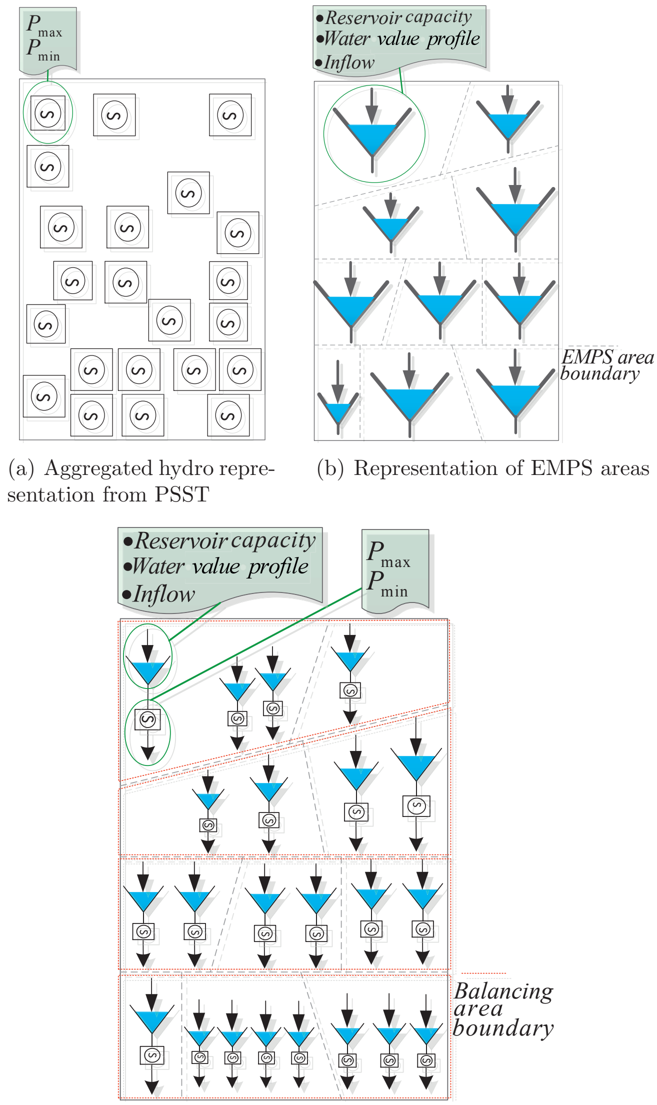


Figure 3.2: Water value matrix for a reservoir in Norway as obtained from EMPS. The water value is generally high when the reservoir level is low and viceversa. Similarly, for a given reservoir level, we can see that the water value is low during high inflow period (late spring and summer) and high during low inflow period.

The detailed hydro modeling approach in this work is as follows. Two set of inputs from two different models; PSST[2] and EMPS are used to constitute the hydro modeling approach in this thesis. 49 aggregated hydro plants are obtained from the PSST model and 18 aggregated EMPS areas from the EMPS model. Each EMPS area is characterized by a reservoir capacity, water value profile, and time series for inflow. The 49 power plants are then distributed to the respective EMPS areas. For example, 4 aggregated hydro plants are assigned to the EMPS area N5 in Fig. 3.8. Each hydro plant is then directly connected to a reservoir where the reservoir capacity and inflow time series are sized relative to the maximum hydro

[2]Power System Simulation Tool (PSST) [74], is a DC optimal power flow based market model, developed by SINTEF Energy Research, that minimizes the total generation costs in the system for each hour of the year.

plant capacity in each EMPS area. Moreover, the reservoirs will take a water value profile of the EMPS area. A number of EMPS areas constitute a balancing area. The hydro power modeling used in this thesis as a combination of inputs from the PSST and EMPS models is shown in Fig. 3.3.



(a) Aggregated hydro representation from PSST

(b) Representation of EMPS areas

(c) Hydro modeling in this thesis

Figure 3.3: Nordic hydro power modeling followed in this thesis by combining inputs from the PSST and EMPS models

A.2 Thermal units Thermal units based on oil, gas, and hard coal are called regulating thermal units. These types of units are characterized by the ability to sufficiently ramp up or down in a short time. On the other hand, thermal units based on nuclear and lignite coal tend to generate at their nominal operating point and require long time to startup and are used to cover the base load, hence referred to as base-load thermal units. Their cheaper marginal cost compared to regulating thermal plants makes them useful for non-stop operation over extended periods. A thermal generation unit has a certain startup cost and a generation cost which is represented by a quadratic function. In this work, the quadratic generation cost function is approximated by linear function (*cf.* Fig. 3.4). As a result, generation cost of thermal units is represented by a constant marginal cost and an operation dependent fixed cost component. In this model, the Northern European system incorporates a total of 340 thermal units, with 217 of them situated in the German system.

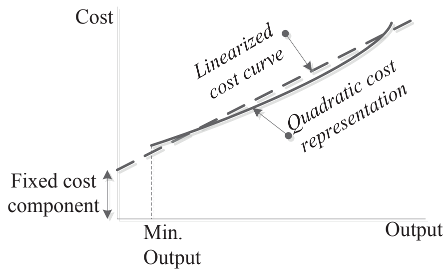


Figure 3.4: Linearized generation cost representation of a thermal unit

A.3 Non-dispatchable units Units whose outputs are difficult or impossible to control fall into this category. The availability of these resources depends on the weather conditions: such as solar radiation for PV plants, wind speed for wind farms, non-storable inflow for ROR hydro plants. We might opt to decrease the output by curtailing the production at a given time but it is not possible to obtain more output than given by the weather conditions. These resources are characterized by zero marginal production cost and will be prioritized in the day-ahead Merit Order List (MOL) and will be fully utilized provided that there are no bottlenecks in the system. Despite some reports of a possibility of wind farms to provide downward regulation (for example in [75]), no FRR provision from these resources is considered in this work.

B Transmission capacity

Depending on the pursued market coupling, NTC or flow-based, the treatment of the transmission capacity varies. For the NTC based formulation, the NTC between balancing areas is used as the exchange constraint in the computations. The NTC between balancing areas and cross-border connections for 2010, are obtained from the ENTSO-E website [76]. In this formulation, both HVDC and HVAC interconnections are treated similarly. For the FBMC consideration, the following are the key differences as compared to the NTC based analysis (*cf.* Fig. 3.6 and Fig. 3.8 for comparison):

- When applying FBMC, flow on AC lines is determined by linearized power flow equations;
- As flow along an HVDC corridor is controllable, it is modelled as a positive or negative net injection;
- Aggregated transmission capacity values between balancing areas are used.

C FRR requirement in Northern Europe

The required FRR capacity in a given region is set by the respective TSO. The TSO ensures that the required reserves are in place for their respective planning periods. In the current market arrangement in Northern European countries, the planning periods are different. In this PhD work, we assume that the planning period is the same for all the countries, with the underlying assumption of harmonized cross-border reserve procurement rules.

Currently, all the TSOs in Northern Europe define and characterize the manual and automatic components of FRR, FRR-M and FRR-A as shown in Table 2.2. As a result, the required volumes, definitions, purposes, and activation of FRR-A and FRR-M are different. In this work, we consider the general FRR without specifying the the automatic and manual components. The definition we follow refers to the reserves that are activated to replace FCR and their purpose being to restore the frequency to its nominal value and to restore the scheduled exchanges. The upward and downward FRR requirements for 2010 in Northern European countries is presented in Table 3.1.

3.1.2 FRR procurement and day-ahead market clearance

In this subsection, variations of the methodologies for FRR procurement and day-ahead market clearance are discussed. The cross-dependency of transmission capacity reservation, choice of sequential or implicit market clearance, and consideration of NTC or FBMC is discussed. Table 3.2 presents the possible combinations of FRR procurement day-ahead market clearance. It also specifies which combinations are considered in this thesis.

NTC is the present approach in the Nordic countries, and is therefore a reference for all reservation cases. The case of No reservation can be seen as a kind of default, and is therefore also considered for FBMC. Moreover, optimal reservation is considered with FBMC, because it is seen as a "second best" to implicit market clearing with optimal reservation. Implicit market clearing with FBMC is included as a potential future market design, and compared with the sequential market clearance options.

Table 3.1: FRR requirement for Northern European countries in 2010: NO-Norway, SE-Sweden, DK-W-Western Denmark, DK-E-Eastern Denmark, FI-Finland, DE-Germany, NL-Netherlands [41, 56, 77–80]

Country	FRR requirement [MW]	
	Upward	Downward
DE	2400	2045
NL	300	300
DK-W	262	262
DK-E	262	262
NO	1200	1200
SE	1220	1220
FI	865	865

Table 3.2: Possible combinations of the FRR procurement and day-ahead market clearance according to market design, market coupling, and transmission reservation criteria. The boxes with letters are considered in this thesis.

	Transmission reservation	NTC	FBMC
Sequential market clearance	No reservation	U	X
	Fixed reservation	V	
	Optimal reservation	W	Y
Implicit market clearance	No reservation		
	Fixed reservation		
	Optimal reservation		Z

The other options with Implicit market clearance are seen as less relevant because fixed reservation seems unnecessary combined with optimal reservation. The No reservation case is also less relevant in this thesis where exchange of reserves is the main focus. All the models are developed on GAMSIDE[3] and employ the CPLEX solver[4].

A No and Fixed reservation of NTC for FRR exchange (U, V)

A sequential market clearance model containing FRR bidding, FRR procurement, and day-ahead market clearance by making use of NTC based implementation, shown in Fig. 3.5, is the core model developed. The formulation is applied to the Northern European power system in the state of 2010, shown in Fig. 3.6. The scope of this section refers to U and V in Table 3.2.

[3]http://www.gams.com/default.htm
[4]http://www-01.ibm.com/software/commerce/optimization/cplex-optimizer

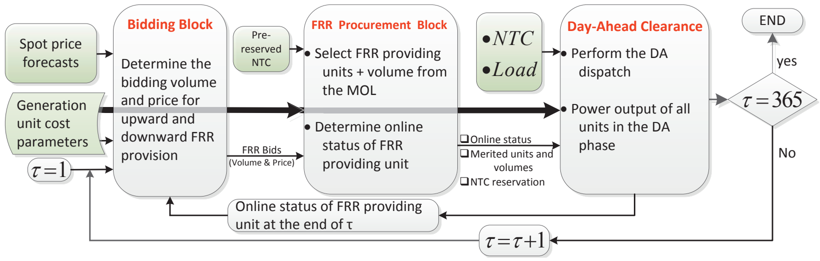


Figure 3.5: Sequential market clearance model with FRR bidding, FRR procurement, and DA clearance in an NTC based implementation.

The first block is the FRR bidding block, where the bid prices for upward and downward FRR provision are estimated. The spot price forecast is the main input, and is used as the basis for estimating a unit's opportunity cost in the day-ahead market. We use a three case approach to determine the bidding prices. Each case represents a unit's profit maximizing optimization task against hourly spot price forecasts for a planning period under a given set of conditions unique for each case. In case 1, there is no commitment for FRR provision. In case 2, the unit provides only upward FRR. In case 3, the unit provides both upward and downward FRR. The difference in profit a unit incurs between case 1 and case 2 as well as case 2 and case 3 represent the unit's cost of commitment to provide upward and downward FRR, respectively. The length of the planning period is considered 24 hours in most of the case studies considered. However, in publication **IV**, a planning period of 12 hours is additionally considered for sensitivity analysis. The complete mathematical formulation and the assumptions considered in this block are thoroughly discussed in publication **I**. It is also featured as a component of the model considered in publications **II**, **III**, **IV** and, **VII**.

The second block, called the FRR procurement block, aggregates the bidding prices and volumes for upward and downward FRR provision provided by the units in a Merit Order List (MOL) and selects the winning bids with the possibility of cross-border FRR procurement. The possibility of cross-border FRR procurement is influenced by the NTC pre-allocated for exchange and the maximum FRR volume one can procure cross-border. Marginally selected units set the FRR price in their respective balancing areas and all units nominated to provide FRR are assumed to stay online for the whole planning period. The objective function is the minimization of FRR procurement cost in a given planning period, roughly shown in (3.1). Complete set of equations are provided in publication **II**.

$$\min \sum_{\forall Gen} r_g^{up} c_g^{up} + r_g^{dn} c_g^{dn} \tag{3.1}$$

The FRR procurement cost is the sum of upward and downward FRR cost where each cost component is given by the product of the FRR bidding price and volume. In (3.1), $r_g^{up/dn}$ represent the up/down-ward bidding volumes and $c_g^{up/dn}$ stand for the up/down-ward bidding prices of a unit g. Some of the main constraints in this block are:

- The FRR requirement should be provided locally or imported.
- The FRR import volume should stay within the limit of the reserved transmission capacity.
- No more than a third of the FRR requirement can be imported.

The underlying mathematical formulation and assumptions for this block are discussed in publication **II**.

The day-ahead market clearance block comes last in the sequence and gets such inputs as, online status of units, procured volumes of upward and downward FRR, and NTC reserved for FRR exchange, from the FRR procurement block. The objective function is to minimize the total day-ahead cost for a given planning period. A simplified representation of the objective function is shown in (3.2).

$$\min \sum_{\forall time} \sum_{\forall Gen} Ec + Sc + Fc + Cc \tag{3.2}$$

The total cost is the sum of energy cost (Ec), startup cost (Sc), operation dependent fixed cost (Fc), and curtailment cost (Cc). The startup and fixed cost are only valid for thermal units. The main constraint in this optimization block is that the maximum generation capacity of a unit is decreased by the upward FRR provision and the minimum is increased by the downward FRR provision. The mathematical formulation and assumptions for this block is discussed in publication **II**.

B Optimal transmission capacity reservation for FRR exchange (W, X, Y)

As opposed to the model shown in Fig. 3.5, i.e. where a fixed NTC reservation is given exogenously, in this section the transmission capacity reservation is optimally determined. Optimal transmission capacity reservation is assessed both with the NTC based and flow-based market coupling formulations. This section refers to W and Y in Table 3.2 for NTC and FB optimal transmission capacity, respectively. Moreover, X in the same table refers to FB formulation with no transmission reservation, used as a reference. A generic model description for optimal transmission capacity reservation for FRR exchange, is shown in Fig. 3.7. The first block, bidding block, is the same opportunity cost based FRR bidding price determination discussed above. In the second block, the FRR procurement and day-ahead markets are co-optimized for a 24 hour block to determine the optimal cross-border transmission capacity reservation. The optimization is a Mixed Integer Programming

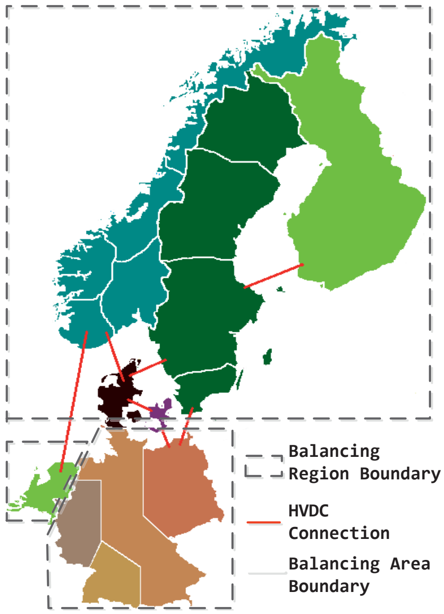


Figure 3.6: Northern European system in 2010 for an NTC based implementation.

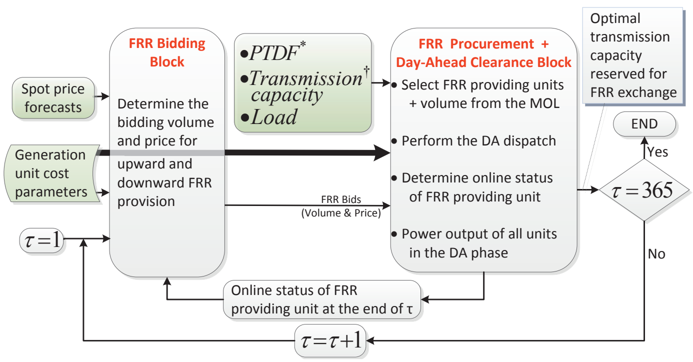


Figure 3.7: Sequential market clearance model for optimal transmission capacity reservation. *Aggregated PTDF values are used only for the flow-based implementation. †NTC values are used for the NTC based implementation and for the flow-based approach, aggregated transmission capacities are used.

(MIP) problem with an objective of minimizing the total cost resulting from the FRR procurement and day-ahead market within the planning period (*cf.* (3.3)).

$$\min \left\{ FRRc + \sum_{\forall time} DAc \right\} \tag{3.3}$$

In (3.3), $FRRc$ represents the FRR procurement cost in the planning period and DAc stands for the hourly day-ahead cost. Some of the main constraints are the following:

- The maximum generation capacity of a unit is decreased by the upward FRR provision and the minimum is increased by the downward FRR provision;
- Transmission reservation can not exceed a certain percentage of the capacity;
- No more than a certain percentage of the FRR requirement can be imported.

For the values of transmission capacity, the NTC values are used in the NTC based implementation and aggregated transmission capacities are used for the flow-based implementation. Moreover, an additional constraint shown in (3.4) is used for the flow-based implementation.

$$p_{x,y}^{AC} = \sum_{z} p_z^{inj}.PTDF_{x,y,z} \tag{3.4}$$

The equation relates the flow along AC line x y, $p_{x,y}^{AC}$, to the PTDF, $PTDF_{x,y,z}$, and nodal injection, p_z^{inj}. The parameter $PTDF_{x,y,z}$ refers to the fraction of flow along x y for a unit injection at z and withdrawal at the reference node. The injection at a given node comes from the sum of generation and HVDC injections minus the load connected. The detailed mathematical formulations and assumptions for this block are discussed in publications **III** and **VII** for NTC and flow-based implementations, respectively.

By varying the planning period and hydro inflow into the system, we assess the sensitivity to these factors of optimal transmission capacity reservation in an NTC based setting. The planning period, the contract period for which reserves are procured, is in most study cases considered 24 hours. A variation of this consideration is to optimally allocate transmission capacity for peak and off-peak periods of a day (i.e. planning period is decreased to 12 hours). Moreover, by considering three inflow scenarios in the Nordic system; a low, a high, and a median inflow scenarios, the impact on optimal capacity reservation is studied. A complete coverage of the sensitivity analysis and the associated findings is discussed in **IV**. The formulation in publications **III** and **IV** is applied to the system in Fig. 3.6. For the flow-based approach presented in publication **VII**, the Northern European system in the state of 2010 updated for a flow-based implementation and shown in Fig. 3.8 is considered.

C Implicit market clearance with flow-based grid constraints (Z)

In this approach, the day-ahead market is cleared with the upward and downward FRR requirements given as constraints to the optimization problem. This approach is denoted by F in Table 3.2. The resolution of the FRR procurement is the same as that of the day-ahead market, 1 hour. Moreover, transmission capacity reservation for FRR exchange is one of the solutions implicitly obtained from the cost

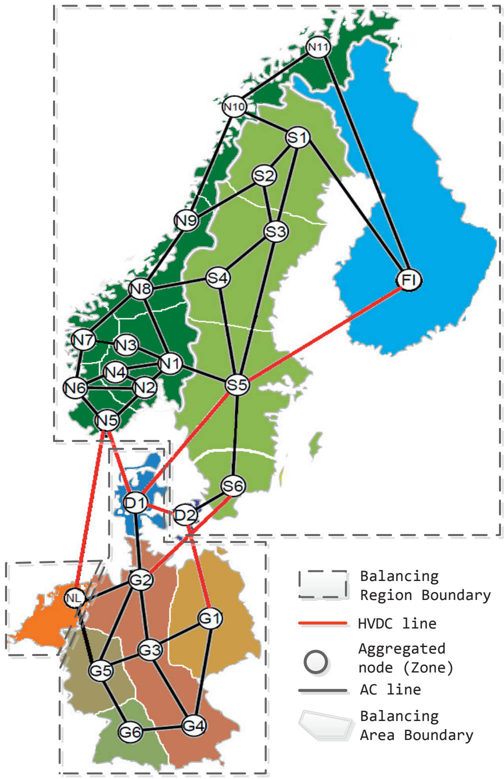


Figure 3.8: Northern European system in 2010 for a flow-based implementation.

minimization problem. Further discussions and associated results of this approach are presented in publication **VII**.

3.1.3 Balancing energy market

A flow-based balancing energy market formulation with a possibility of cross-border balancing is developed. We assume that the day-ahead market clearance results are known and a regulating unit is ready to deviate from its generation set point in the day-ahead market, for balancing purposes, as long as there is a margin to change its output. The methodology is adapted to address NTC based balancing market formulation for comparison. The upward regulation bidding price from a unit is the marginal cost of the unit and the downward regulation bidding price as the maximum of zero and the difference between the spot price and the marginal cost of the unit. The simplified objective function is shown in (3.5) and it minimizes the total balancing cost, which is the sum of upward and downward regulation cost.

$$\min \sum_{\forall time} \sum_{\forall Gen} \Delta p_{g,t}^{up} C_{g,t}^{up} + \Delta p_{g,t}^{dn} C_{g,t}^{dn} \tag{3.5}$$

$\Delta p_{g,t}^{up/dn}$ respectively refer to the change in output of the unit upward or downward from its current generation state. Moreover, $C_{g,t}^{up/dn}$ are the corresponding regulation prices for upward and downward regulation of a unit at a given time, t. The following list presents some of the main constraints in the optimization problem.

- The export/import of balancing power along a line is limited by the transmission capacity and the power exchange along the line in the day-ahead market.
- A unit regulates upward or downward in relation to its output in the day-ahead market, maximum and minimum generation capacities.
- The incremental injection in a given node is the sum of incremental generation and positive nodal imbalance. A positive imbalance means that the system is long and vice versa.

The upward balancing energy exchange in a given time is defined in terms of the net nodal injection, ΔP_z^{inj}, and the PTDF values, $PTDF_{x,y,z}$, as shown in (3.6).

$$p_{x,y}^{up} = \sum_{z} \Delta P_z^{inj}.PTDF_{x,y,z} \tag{3.6}$$

The model is tested on an aggregated version of the IEEE 30-bus test system, shown in Fig. 3.9. The simplicity of the test system and suitability for detailed analysis is the main reason for the choice. A detailed presentation and discussion of the approach and mathematical modeling is found in publication **VI**. The network aggregation methodology followed is discussed in publication **V**. This aggregation methodology is also the basis for the case study considered in publication **VII** (*cf.* Fig. 3.8).

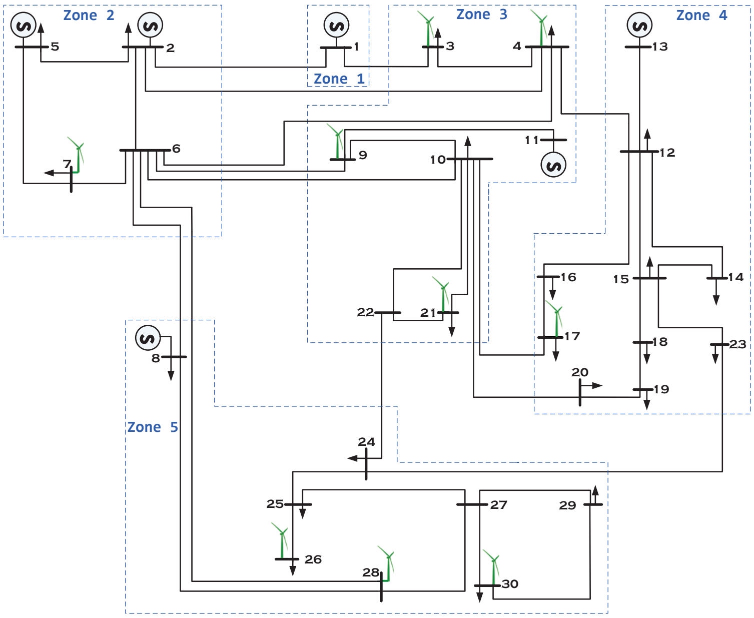


Figure 3.9: Single line diagram of the modified IEEE 30-bus test system [81]. The original IEEE 30-bus test system is without wind power plants [82].

3.2 Summary of publications

In this section, a summary of the main publications is presented. Table 3.3 shows the categorization of the publications according to the case studies considered and the theme (reserve procurement or balancing energy market). Two systems are considered as case studies: the Northern European power system and the IEEE 30-bus test system.

Table 3.3: Allocation of publications according to focus area and methodology

Approach	Study system	Reserve procurement	Balancing energy market	PTDF aggregation
NTC based	Northern Europe	Publication **I** Publication **II** Publication **III** Publication **IV**		
Flow-based	Northern Europe	Publication **VII**		
	IEEE 30-bus test system		Publication **VI**	Publication **V**

3.2.1 Bidding in the FRR market, FRR procurement, and cross-border transmission capacity reservation

This section gives a summary of the following publications.

I *Bidding in the Frequency Restoration Reserves (FRR) market for a Hydropower Unit*, Y. Gebrekiros, G. Doorman, S. Jaehnert, and H. Farahmand, 4th IEEE/PES Innovative Smart Grid Technologies Europe (ISGT EUROPE) conference, Copenhagen, Denmark, 6-9 October 2013 and

II *Reserve Procurement and Transmission Capacity Reservation in the Northern European Power Market*, Y. Gebrekiros, G. Doorman, S. Jaehnert, and H. Farahmand, International Journal of Electrical Power and Energy Systems (IJEPES), vol. 67, pp. 546–559, May 2015.

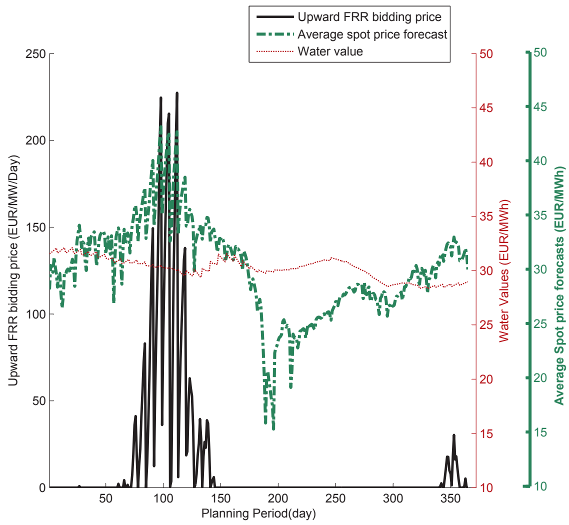
> In publication **II**, the core modelling for the NTC based FRR bidding price determination, FRR procurement with cross-border exchange possibility, and integrated day-ahead market clearance is presented. Publication **I** focuses on the bidding price determination for FRR provision of a hydropower unit. It is essentially an in-depth study of the first block of the model considered in publication **II**.

*Publication **I**:*
The expected opportunity cost in the day-ahead market for a given period is used to determine the bidding prices for FRR provision for a hydro unit. For a given planning period, the following assumptions are made in the formulation. A unit makes a profit of B_1 without any commitment to provide FRR; a profit of B_2 by only committing to provide upward FRR; and a profit of B_3 when it provides both upward and downward FRR. Due to the increasing constrains, the following relation holds: $B_3 \leq B_2 \leq B_1$. As a result, $B_1 - B_2$ and $B_2 - B_3$ represents the cost of upward and downward reserve provision respectively. Dividing the changes in profit with the respective volume of FRR gives the bidding prices. The maximum bidding volume for the unit is taken to be 20 % of the maximum generation capacity.

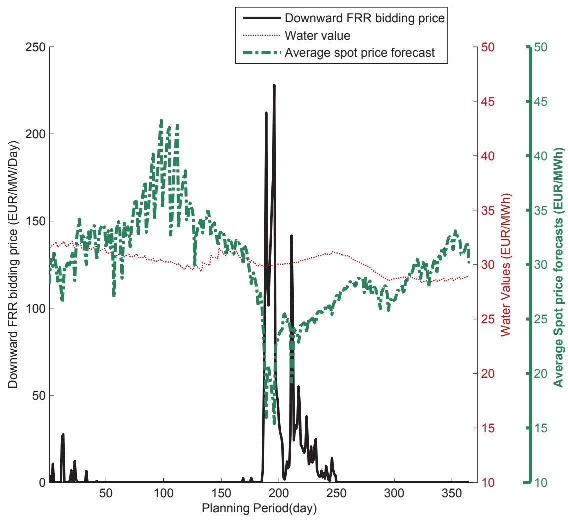
Taking a typical hydropower unit in Southern Norway as a case study, the following main results are obtained (*cf.* Fig. 3.10)

- When average spot price is higher than the water value, a unit tends to operate at maximum. However, if it has to provide upward FRR, then the reduction in profit in the day-ahead market should be compensated by higher upward FRR bidding price.

- When the water value is higher than the spot price forecast, a unit does not normally run. But, if it should operate and provide downward FRR, then the loss should be evened out by higher downward FRR price.



(a) Upward FRR bidding price



(b) Downward FRR bidding price

Figure 3.10: Upward and Downward FRR bidding price versus water values and average spot price forecasts for a hydropower unit

*Publication **II**:*
In this paper, the detailed mathematical formulation that resembles the current

market clearance sequence in Northern Europe and consisting of the three consecutive optimization blocks is presented and applied to a case study.

The first block is an MIP optimization problem where, for a given period, reserve providing units determine their FRR bidding prices. This block is extensively discussed in publication **I**. The second block, FRR procurement block, is a Linear Programming (LP) optimization problem that takes bidding prices and volume offers from the first block and selects the winning bids from the merit order list with a possibility of cross-border FRR exchange. Transmission capacity reservation for FRR exchange for 0 %, 2 %, 5 %, 7 %, 10 %, 15 %, 20 %, 25 %, 30 %, and 35 % of the NTC on all corridors are considered for the analysis. By considering that (a) the units with winning bids from the second block stay online for the period they are contracted for, (b) the NTC value for the day-ahead period is reduced with the capacity reserved for FRR exchange, and (c) the input from all units participating in the day-ahead market (MC, startup costs, fixed costs, generation limits, etc) is provided, the third block is cleared. This block solves a MIP problem by minimizing the total day-ahead costs.

The main results from this work as applied to the Northern European system with the topology and inputs of 2010 are:

- Transmission capacity reservation for FRR exchange can reduce the total cost compared to no reservation case. For the considered system, the lowest total cost is registered at an NTC reservation of 20 %.
- The FRR procurement costs decrease with increase in reserved capacity as a result of procuring cheaper FRR cross-border.
- The day-ahead cost decreases for small shares of NTC reservation and is the lowest for 5 % NTC reservation (*cf.* Fig. 3.11). The explanation for this is that, for small value of reservation, procuring FRR from another system reduces the need to keep FRR in the expensive system, which increases the flexibility and reducing the day-ahead cost. In other words, it avoids the possibility that an expensive unit is only running to provide FRR; which in turn creates a must run condition in the day-ahead market for the whole planning period.
- Given the possibility of cross-border FRR procurement, more upward FRR is procured from Norway, Sweden, and the Netherlands compared to their requirement. On the other hand, Germany becomes a major importer. The results are valid under the assumptions made and may not be a general conclusion.

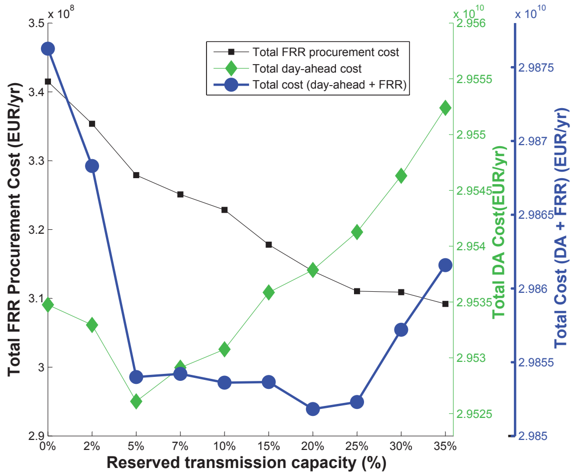


Figure 3.11: Annual procurement costs vs. transmission capacity reservation for FRR exchange

3.2.2 NTC based optimal cross-border capacity reservation using a sequential market clearance setting

This section provides a summary of publications **III** and **IV**.

III *Optimal Transmission Capacity Allocation for Cross-border Exchange of Frequency Restoration Reserves (FRR)*, Y. Gebrekiros and G. Doorman, 18th Power Systems Computation Conference, Wroclaw, Poland, 18-22 August 2014 and

IV *Sensitivity Analysis of Optimal Transmission Capacity Reservation for Cross-border Exchange of Reserve Capacity in Northern Europe*, Y. Gebrekiros, S. Jaehnert, and G. Doorman, 11th International Conference on the European Energy Market (EEM), Krakow, Poland, 28-30 May 2014.

The mathematical formulation to optimally allocate transmission capacity for FRR exchange using an NTC based implementation is laid out in publication **III**. The formulation is applied to the 2010 Northern European power system. Without altering the mathematical premise, the impact of changing the planning period and the hydro inflow is addressed in publication **IV**.

Publication ***III***:
An NTC based two block optimization problem using the sequential market clearance in Northern Europe is solved to optimally allocate transmission capacity for cross-border FRR exchange.

The first block is the FRR bidding price formulation (explained in publications **I** and **II**). The second block gets the FRR bidding price and volume offers from the first block and inputs needed in the day-ahead market. It then solves an MIP problem to obtain the optimal transmission capacity reservation by minimizing the day-ahead and FRR procurement costs for a given planing period. The planning period for the FRR procurement is 24 hours and the resolution of the DA market is 1 hour. For reliability purposes, $\frac{2}{3}$ of the FRR requirement is procured locally, and no more than 30 % of the NTC can be reserved for FRR exchange.

By considering the Northern European system of 2010 topology and inputs, the results of the optimal transmission capacity reservation are discussed in light of a base case where no transmission capacity reservation is possible.

- With optimal transmission capacity reservation, a reduction of EUR 26.1 million ($\approx$ 8 %) in FRR procurement and EUR 53 million in total costs is obtained compared to the base case.
- Because of the multiple balancing area interactions, transmission reservation restrictions, and FRR procurement limits, the transmission capacity reservation is characterized by upper and lower bounds.
- Transmission capacity reservation along the Nordic-German and Nordic-Dutch systems is significantly lower in periods with reduced hydro availability, in the simulations before the start of the snow meting season. This increases the spot prices and consequently the opportunity costs for upward FRR provision, lowering the reservation of transmission capacity.
- Compared to national requirement, more upward FRR is procured from Norway, Sweden, and Netherlands. The excess is then exported to Germany, Denmark, and Finland, inline with the observation in publication **II**.

Publication ***IV***:
Following the same mathematical framework as in publication **III**, this paper analyses the sensitivity of the results for changes in inflow scenarios and the length of the planning period.

This work considers the same system and inputs as in publication **III**. To assess the impacts of inflow variation on total system cost, optimal transmission reservation, and country wise FRR procurement, three inflow scenarios in the Nordic system are considered. These are, the dry year, a year with the lowest inflow; the wet year, a year with the highest inflow; and the median year, a year with median inflow. Moreover, to assess the impact of planning period duration on the mentioned parameters, a shorter planning period of 12 hours (with peak and off-peak periods of a day) is considered. The main findings are:

- Reduction of the planning period to 12 hours, with peak and off-peak daily periods, provides more flexibility to the system. For the median inflow, this results in about EUR 236 million (≈ 1 %) reduction in total cost compared to when the planning period is 24 hours.

- The upward FRR procurement costs are the highest for the wet year compared to the medium and dry year scenarios. In this scenario, the reservoir levels are relatively higher at any given time making the water value comparatively lower. Hence, the unit is better off generating in the day-ahead market than standing by to provide upward FRR. This makes the upward bidding prices during the wet year scenario relatively high, thus resulting in the highest upward FRR procurement costs.

- The trend of per country FRR procurement is neither affected with the inflow variation nor with the change in planning period. More upward reserves are procured from Norway, Sweden, and the Netherlands compared to their requirement for all cases.

3.2.3 Assessment of PTDF based power system aggregation

This section summarizes publication **V**. This is slightly out of the main theme of the thesis, but it is presented here as it is the basis for the PTDF aggregation approach followed in publications **VI** and **VII**.

V *Assessment of PTDF Based Power System Aggregation Schemes*, Y. Gebrekiros, G. Doorman, A. Helseth, and T. Preda, 2015 Electrical Power and Energy Conference (EPEC), London, ON, Canada, October 26-28, 2015.

In this work, three different PTDF aggregation schemes are compared. The performance of the aggregation schemes is analyzed by considering the power generation, inter-zonal flows, and total system costs in relation to the nodal representation of the IEEE 30-bus test system.

Out of necessity or data limitation, aggregated power system representation is required. In PTDF based power system aggregation, nodal PTDFs are aggregated into zonal PTDFs that give similar inter-zonal flows. The nodal PTDF values are determined from line reactances and aggregation to zonal PTDFs is done using three schemes. The first scheme assigns equal weighting factors for each node in a zone (pro rata); the second and third schemes assign nodal weights from relative nodal net injections and nodal generations respectively.

The main results after running a DCOPF on the system, performed by considering two scenarios is presented as follows.

1. *With perfect foresight of nodal generation and injections*
   This is considered as a benchmark and analysis is done on the IEEE 30-bus test system.

   - As expected, the aggregation scheme using relative nodal injection in a given zone gives exact results as the nodal system.

   - The aggregation scheme that is based on nodal generations only works if there is generation in every zone. This is not the case in one zone of the test system; thus, this scheme is not tested.

2. *Under uncertainty due to wind and load forecasting errors*
   Analysis is done on a modified version of the IEEE 30-bus test system which includes wind generation. In real systems, knowledge of the nodal injections ex-ante is limited, which instead must be forecasted.

   - Under uncertainty, the two other PTDF aggregation schemes give better system representation compared to the pro rata scheme. However, the pro rata scheme might have some comparative advantages over the other schemes in the following ways:

  - Unlike the other two schemes, it allows the predetermination of the zonal PTDFs.

  - Always numerically stable unlike the other two which can face instabilities (division by zero) if the sum of net injections or net generation in any given zone is zero.

- By introducing an offset to correct deviations, the aggregation based on nodal generation gives the lowest inter-zonal flow errors.

- The choice of a PTDF aggregation scheme depends on the quality of the forecasts, simplicity of the PTDF aggregation, numerical stability of the aggregation method, and desired accuracy of the results.

3.2.4 Flow-based optimal transmission capacity allocation for FRR exchange

This section summarizes the following publication.

VII *Flow-Based Optimal Transmission Capacity Allocation for Cross-border Reserves Exchange*, Y. Gebrekiros, S. Jaehnert, and G. Doorman, Submitted to IEEE Transactions on Power Systems.

This work discusses flow-based optimal transmission capacity reservation following a sequential market clearance for FRR exchange in the Northern European power system. It compares sequential market clearance with an implicit market clearance option. The detailed mathematical modeling is presented and an additional assessment of sequential market clearance with no transmission capacity reservation is carried out.

In this publication, the following cases are analysed.

1. Sequential market clearance without cross-border transmission capacity reservation.

In this case, as there is no transmission capacity reserved, there is no possibility of cross-border FRR procurement.

2. Sequential market clearance with optimal cross-border transmission capacity reservation.

The mathematical description of the flow-based optimal transmission capacity allocation for cross-border FRR exchange uses a model with two optimization blocks. The first block is the bidding block ($cf.$ publication **I**), where as the second block determines the optimal transmission capacity reservation by optimizing the FRR procurement and day-ahead costs considering the grid constraints.

3. Implicit market clearance with a possibility of cross-border FRR exchange.

The implicit market clearance option considered here has a resolution of 1 hour; i.e. FRR procurement and transmission capacity reservation are done on an hourly basis.

By still considering the 2010 Northern European system as a case study, the main results from the paper are presented below.

- Compared to the base case (no transmission capacity reservation), the sequential market clearance with optimal transmission reservation option gives a saving of EUR 19 million. The implicit market clearance option, on the other hand, gives EUR 413 million saving compared to the base case. The significant total cost reduction results from the attributes of implicit market clearance; being an efficient market design option and the short planning period of FRR provision.

- Duration curves of annual optimal transmission capacity reservation for the sequential and implicit market options show a number plateaus as a result of the multiple balancing area interactions, transmission reservation restrictions, and FRR procurement limits considered in the study. See, for example, the transmission capacity reservation on Skagerrak HVDC cable in Fig. 3.12.

- In the implicit market clearance option, the planning period being 1 hour, there could be a number of hours where no transmission is reserved in a given day. As a result of this flexibility, the percentage duration where no transmission capacity is reserved is longer compared to the sequential option on all interconnections.

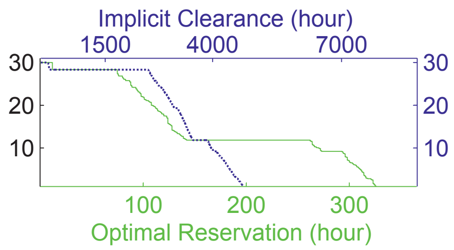


Figure 3.12: Sorted optimal transmission capacity reservation for sequential market clearance (green line) and implicit market clearance (blue dotted line) for Skagerrak HVDC cable [% of max. capacity].

3.2.5 Flow-based balancing energy market integration

This section presents a summing up of the publication below.

VI *Balancing Energy Market Integration Considering Grid Constraints*, Y. Gebrekiros, G. Doorman, S. Jaehnert, and H. Farahmand, PowerTech conference, Eindhoven, Netherlands, 29 June-2 July, 2015.

> This work provides the mathematical modelling of balancing energy market integration using a flow-based and NTC based implementations. The impact of cross-border exchange of balancing energy is studied on an IEEE 30-bus test system. It assumes that the day-ahead market has already been cleared and the results are known.

Each unit determines its upward and downward balancing energy bid prices as a function of its marginal cost and the spot price. The TSO then selects the bids from the merit order list based on the real-time system imbalances. Both the flow-based and NTC based implementations adhere to these notions except that power flow constraints and NTC restrictions are considered for the first and latter respectively. The NTC values are estimated from the transmission capacities iteratively, as in Fig. 3.13. A modified IEEE 30-bus test system, aggregated into 5 zones and incorporating large scale wind integration is considered for the study. The imbalances are generated from load and wind forecast errors.

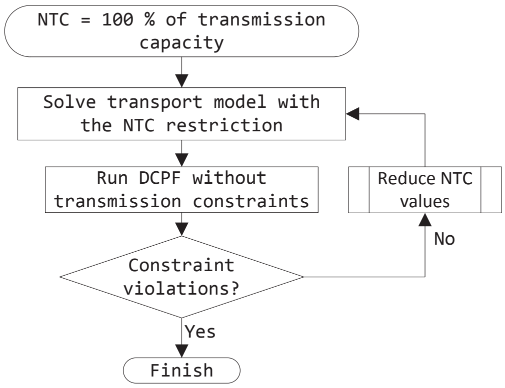


Figure 3.13: Flowchart for NTC calculation

The main results of this work are presented below.

- In both arrangements (NTC and flow-based), the balancing energy costs are reduced when there is inter-zonal exchange of balancing energy. The decrease in balancing costs is a result of the netting of imbalances and the use of cheaper balancing energy from neighbouring zones.

- For both arrangements, a significant decrease of about 50 % in average imbalances is obtained as a result of allowing inter-zonal balancing energy exchange.

Since the considered test system is small, with little meshing and no inter-zonal congestions, the net imbalances for both arrangements are identical.

Chapter 4

Conclusions

In this PhD work, balancing market integration in the European power system is studied. This work contributes to the research topic by developing models for reserve procurement and balancing energy markets. These models are applied to case studies of the Northern European power system and the IEEE 30-bus test systems. This work has two main contributions. The first is the development and detailed interdependence among reserve procurement, day-ahead market clearance, and balancing energy market. This is done by making use of two separate models where the first one incorporates unit based bidding price determination for reserve provision, reserve procurement with a possibility of cross-border exchange, and day-ahead market clearance. The second one deals with balancing energy market formulation by taking the results of the day-ahead market clearance into account. The other main contribution is the modeling approach that uses a setting similar to the current sequential market clearance order in Northern Europe, where previous research often used an integrated or implicit design. The models are used to analyze the impact of balancing market integration in the current electricity market settings and allow the comparison of two fundamentally different market designs.

The European electricity market, and the day-ahead market specifically, has been subjected to integration efforts with the long-term goal of establishing a Pan-European electricity market. An integrated market is expected to increase the overall efficiency, competition, security of supply, and social welfare. Similarly, the integration of balancing markets, although in a much smaller economic scale compared to the day-ahead market, is also expected to give a socio-economic benefit. The reason is that, common balancing market offers economic benefit in the form of sharing of balancing resources, reduced activation costs through the use of the cheapest available units, and the reduction of required balancing actions by evening out the activation of counteracting balancing actions in adjacent areas. However, for the realization of fully integrated balancing market, at least some market design elements have to be harmonized first. The existence of such regulatory arrangements is taken as a main assumption in the mathematical formulations and the associated results in this work.

To assess the impact of balancing market integration, two main optimization models have been developed: one addressing cross-border reserve procurement and another dealing with balancing energy market integration. The main modeling blocks are summarized as follows:

- *Reserve bidding price determination* - By making use of spot price forecasts, the bidding prices for the provision of upward and downward reserves are determined on the basis of the opportunity cost for the units in the day-ahead market.

- *Reserve procurement market* - The bidding prices for reserve provision provided by the units are aggregated in a system wide common merit order list and bids that result in the least reserve procurement cost are selected. Units selected to provide reserves must stay online for the whole period the reserves are contracted for. The reserve procurement incorporates different options for the allocation of cross-border transmission capacity.

- *Day-ahead market clearance* - Taking the online status of reserve providing units, and procured volume of upward and downward FRR from the reserve procurement phase, system wide day-ahead market is cleared with the objective of minimizing the total day-ahead costs.

- *Balancing energy market* - Based on the results of the day-ahead market clearance, a regulating unit is ready to change its generation for balancing purposes as long as there is a margin to change its output. For a given generation unit, the deviation from its day-ahead set-point results in a regulation cost. This is used as a basis to determine the bidding price for upward and downward regulation of the unit.

With some modification and rearrangement of the blocks specified above, a methodology to optimally allocate cross-border transmission capacity using a framework based on Net Transfer Capacities (NTC) is also developed. On the basis of the ongoing developments towards flow-based market coupling (FBMC) in Europe, an alternative formulation based on this approach is finally developed to compare the results with the NTC based formulation.

4.1 Main results

The main findings of this thesis grouped in their respective focus areas are the following:

4.1.1 NTC based sequential market clearance

The effect of reserving NTC capacity for FRR exchange is analyzed by allocating equal percentages of NTC on all corridors for a whole year. As expected, the FRR procurement costs decrease with an increase in reserved transmission capacity if there is access to cheaper FRR cross-border. Naturally, this is in general counteracted by a cost increase in the day-ahead market. However, it appears that for small shares of reserved transmission capacity (in this particular study, up to 5 %), the day-ahead costs also decrease, resulting in a win-win situation. The explanation for this result is that, the possibility to import some FRR cross-border and reducing the local FRR provision correspondingly, increases the flexibility of the generation system in the "expensive" area. This leads to a cost reduction in the day-ahead market. Thus, transmission capacity reservation for FRR exchange can reduce the total cost in relevant cases.

With the possibility of cross-border FRR procurement, more upward FRR is procured from Norway, Sweden, and the Netherlands. On the other hand, Germany imports some of its FRR requirement. The cheaper, hydro based, FRR provision from Norway and Sweden makes them provide more upward FRR compared to their requirements. On the other hand, thermal generation dominated Netherlands has lower FRR requirement per peak load compared to Germany, making the Netherlands a net exporter of upward FRR.

4.1.2 NTC based optimal transmission capacity reservation

Allocating a fixed share of NTC for FRR exchange over a long period of time is not expected to give the best result for several reasons. First, the NTC allocation might only be necessary in some periods of time but not in others. Secondly, transmission capacity reservation for FRR exchange might be very important in some corridors where as other corridors might be better off using the whole NTC for energy exchange. As a result, an allocation approach that is specific both in time period and cross-border corridor is expected to give better results. Hence, by using an NTC based methodology to optimally allocate transmission capacity for FRR exchange with a planning period of 24 hours, a reduction of EUR 26 million ($\approx$ 8 %) in FRR procurement and EUR 53 million in total costs is obtained compared to the base case of no reservation. This result confirms the finding in the previous section: optimal reservation of NTC for FRR can reduce both FRR procurement costs and day-ahead costs simultaneously.

Transmission capacity reservation along the Nordic-German and Nordic-Dutch corridors is significantly lower in periods with low hydro availability. In these periods, the spot prices increase, which increase the opportunity costs for upward FRR provision, reducing the profitability of reserving transmission capacity.

An important market design feature is the length of the period that reserve capacity is procured. In general, longer periods are expected to increase costs, as they force units to stay running through periods where the price is too low, or restrict units from generating at their maximum when prices are high. In most cases of the present work, a reservation period of 24 hours has been used. For the model with NTC based optimal transmission capacity reservation, a sensitivity analysis using a

12 hours reservation period showed very significant cost reductions. This confirms the expectations, and underlines the importance of short reservation periods for reserve procurement.

The wet year scenario results in the highest upward FRR procurement cost compared to the medium and dry year scenarios. At any given time, the reservoir levels are the highest for the wet year lowering the water value. Hence, a unit is better off generating in the day-ahead market than standing by to provide upward FRR. This results in the highest upward FRR bidding prices for the wet year scenario, which subsequently increase the upward FRR procurement costs. On the other hand, the total cost is the lowest for the wet year scenario and the highest for the dry year scenario.

4.1.3 Flow-based optimal transmission capacity reservation

The implicit market clearance option, where the reserve requirement is implicitly considered as a constraint in the day-ahead market clearance should, from a theoretical point of view, be a more efficient market clearance option than the sequential market clearance with optimal transmission capacity reservation. This is because, primarily, of the flexibility due to short reserve procurement period, 1 hour in this work, compared to the 24 hours in the sequential market clearance. Secondly, the day-ahead market clearance in the sequential market clearance option is constrained by the decisions made in the reserve procurement phase. For instance, a unit selected to provide reserve creates a must-run condition in the day-ahead market for that planning period. This assumption is confirmed by the simulations, where the sequential market clearance with optimal reservation results in a saving of EUR 19 million. The implicit market clearance, on the other hand, gives a saving of EUR 413 million both compared to the case with no transmission capacity reservation.

The short planning period of the implicit market clearance, i.e. 1 hour, avoids the need for reservation of transmission capacity during some periods in a given day. As a result, in the implicit market clearance, there is a possibility where no transmission capacity is reserved in some hours of a given day. Thus, in all interconnections, the percentage duration where there is no transmission capacity reservation is longer in the implicit market clearance compared to the sequential option.

4.1.4 Balancing energy market integration

A possibility of cross-border balancing energy exchange lowers the the balancing costs compared to local balancing. This is because, firstly, the net imbalances are lower than the total imbalances because of cancelation of opposing imbalances with the neighbouring zones. Secondly, with cross-border balancing energy exchange, there is a possibility of utilizing cheaper balancing resources from neighbouring zones. By making use of the IEEE 30-bus test system as a case study, and using both NTC and flow-based cross-border balancing market implementations, we find a significant decrease in balancing energy costs.

In general, flow-based market coupling approach utilizes transmission capacity better compared to an NTC based approach, which can improve the relative efficiency of flow-based market coupling. In this case study, flow-based integrated balancing energy market clearance results in about 20 % lower balancing cost compared to the NTC based.

4.2 Recommendations for future work

This PhD work dealt with the modelling and analysis of balancing market integration in Northern Europe. The following is a discussion of some aspects where this work can be extended.

The case study considered in most of the publications is the Northern European system in the state of 2010. In the near future, the Northern European system is expected to be more interconnected compared to its status now (the possible realization of the North Sea offshore grid is one example). Besides, the Northern European system will integrate more wind (both offshore and onshore) and solar power generation into the network. These two factors are very important for balancing market integration: 1) The limited predictability and controllability of RES integration is an important issue in balancing given that the proportion of RES in the power mix increases. 2) The increasing interconnections increase the interactions and sharing of resources between systems, highlighting the significance of transmission reservation for reserves exchange. As a result, consideration of more case studies referring to the future states of the Northern European system are important.

In European power markets, an intra-day market typically exists between the day-ahead market and balancing energy activation. Getting close to the actual time of energy delivery, the system understanding increases and the accuracy of the forecasts get better. Thus, the portfolio adjustments in the intra-day market, relieve the burden in the balancing energy market by reducing the imbalances. Hence, when designing a sequential market model that follows the actual order in practice, every market component should be considered. As a result of the change in inputs (imbalances, and generator operating set points), the results associated with balancing energy market might be different. Hence, future work should incorporate the intra-day market as a part of the sequential market clearance model.

According to the current ENTSO-E classification of reserves, manual and automatic components of FRR (FRR-A and FRR-M) are identified. In this work, we only considered general FRR. It would therefore, be important that future work makes a distinction of FRR-A and FRR-M and their interactions.

In this work, the FRR bidding prices are determined in relation to the opportunity cost the unit could incur in the day-ahead market. Thus, the impact of activation in the balancing energy market is not taken into account in the estimation of FRR bidding prices. Consequently, FRR bidding prices might be slightly over estimated. Hence, future work could account for the activation in the balancing energy market when estimating the FRR bidding prices.

In a deregulated power system, a producer might own a number of generation plants. In this work, the general assumption taken is that each unit has a separate owner, thus the FRR bidding prices are estimated for individual units. As FRR provision leads to a must-run condition for the whole FRR procurement period, this reduces the unit's flexibility in the day-ahead market rising the FRR bidding prices. With multiple units, on the other hand, a producer gets more flexibility, thus lowering the FRR bidding prices. Further work should, therefore, consider portfolio bidding for FRR provision.

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Appendix A

Publication I

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Appendix B

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Reserve procurement and transmission capacity reservation in the Northern European power market

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ABSTRACT

This paper provides the modeling approach and the associated results of determination of bidding prices for frequency restoration reserves (FRR) provision, and implications of cross-border transmission capacity reservation for FRR exchange. A model with three optimization blocks is developed. The FRR bidding price determination block uses an opportunity cost based approach to calculate the cost of providing FRR. For the FRR procurement, the transmission system operator (TSO) selects the cheapest bids with the possibility of cross-border exchange if transmission capacity is reserved for this purpose. In the day-ahead procurement block, optimal unit commitment and dispatch is determined, taking into account the reserve and transmission capacity allocations.

A case study is done for the Northern European power system, consisting of the Nordic countries, Germany and the Netherlands. The results show how, among others, the FRR bidding prices are determined by the difference between the daily averaged sport price forecasts and the units' marginal costs. The day-ahead and total reserve procurement costs are positively and negatively correlated to the system load respectively. As could be expected, costs are reduced in the FRR market when transmission capacity is reserved for this purpose. But a decrease in cost in the day-ahead market was also obtained for small transmission capacity reservations, caused by the increased flexibility in the FRR importing market. The total costs are the lowest for a transmission capacity reservation level of around 20%, illustrating that such reservation can be beneficial.

Introduction

An increasing share of the generation mix in the European power system is covered by non-dispatchable renewable energy sources (RES); predominantly wind and solar. The share is expected to rise even more in the following years. In 2012, in the German system, RES contributed 25% of the energy demand and the installed wind and photovoltaic (pv) capacity amounted to 31 GW each [1,2]. Besides, the European Wind Energy Association (EWEA) targets 230 GW of wind power capacity in Europe by 2020 [3]. On the one hand, the integration of RES is an important step in relieving the dependence on fossil fuel based power generation. The massive penetration of these resources, on the other hand, is not with out challenges. RES are generally intermittent and characterized by limited predictability and controllability. Several studies show that these characteristics call for more operating reserves with fast response, to secure the system balance [4–6].

In addition to the increasing RES integration, more interconnectors are linking European countries and in the coming decade, several new ones are expected to be commissioned [3]. At the same time, significant progress has been observed in the progress towards a pan European electricity market. An initiative launched in 2010, the Central Western European (CWE) coupling, which covers Netherlands, Belgium, France, Germany and Luxembourg, creates a single platform for day-ahead electricity trading [7]. Following this, Interim Tight Volume Coupling (ITVC) resulted in increased efficiency of the European power system by coupling the day-ahead market of the CWE region, with the Nordic market. Meeus et al. [8] discuss in detail the regional successes of electricity market integration initiatives in Europe.

To keep the system frequency at the nominal operating value, the instantaneous balance between demand and supply should be met. For economic reasons, it is fairly impossible to store electricity in a large scale. Hence, there is a need for reserve capacity

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Nomenclature

Sets

A	set of balancing areas
T	set of time periods
R	set of balancing regions
Γ	set of planning periods
H, H_a	set of hydro units, hydro units in area a respectively
G, G_R, G_B, G_a	set of thermal, regulating thermal, base load thermal, and thermal units in area a respectively
X	set of reservoir segments
A_r	set of balancing areas in balancing region r

Indices

a, b	balancing area
r, s	balancing region
τ	planning period
t	time period within τ
g	thermal unit
h	hydro unit
x	reservoir segment

Parameters

$\overline{P}_{a,g}, \underline{P}_{a,g}$	maximum and minimum generation capacity of thermal unit g in area a (MW)
$\overline{P}_{a,h}, \underline{P}_{a,h}$	maximum and minimum generation capacity of hydro unit h in area a (MW)
$\overline{P}^{s}_{a,\tau,t}$	solar power capacity in area a at t (MW h)
$\overline{P}^{w}_{a,\tau,t}$	wind power capacity in area a at t (MW h)
$\mathrm{PL}_{a,\tau,t}$	load level in area a at t (MW h)
$\mathrm{MC}_{a,g}$	marginal cost thermal unit g in area a (EUR/MW h)
$\mathrm{WV}_{a,h,x,\tau}$	water value of a hydro reservoir of h in area a for a reservoir segment x at τ (EUR/MW h)
$\mathrm{SP}_{a,\tau,t}$	spot price forecast of area a at t within planning period τ (EUR/MW h)
$\mathrm{SC}_{a,g}$	startup cost of thermal unit g in area a (EUR)
$\mathrm{FC}_{a,g}$	fixed cost of thermal unit g in area a when running (EUR)
VLL	rationing cost (EUR/MW h)
$\overline{L}_{a,h}$	maximum reservoir level of hydro reservoir associated with unit h in area a (MW h/h)
$Q^{st}_{a,h,\tau}$	storable inflow to reservoir associated with h in area a within planning period τ (MW h/h)
$Q^{ns}_{a,h,\tau}$	non-storable inflow to reservoir associated with h in area a within planning period τ (MW h/h)
$\overline{R}^{\uparrow}_{a,g}, \overline{R}^{\downarrow}_{a,g}$	maximum upward and downward FRR capacity offer from thermal unit g in area a (MW)
$\overline{R}^{\uparrow}_{a,h}, \overline{R}^{\downarrow}_{a,h}$	maximum upward and downward FRR capacity offer from hydro unit h in area a (MW)
$c^{\uparrow}_{a,g,\tau}, c^{\downarrow}_{a,g,\tau}$	upward and downward FRR bidding price of thermal unit g in area a for planning period τ (EUR/MW)
$c^{\uparrow}_{a,h,\tau}, c^{\downarrow}_{a,h,\tau}$	upward and downward FRR bidding price of hydro unit h in area a for planning period τ (EUR/MW)
$Rr^{\uparrow}_{a,\tau}, Rr^{\downarrow}_{a,\tau}$	upward and downward FRR required in area a for planning period τ (MW)
$\mathrm{NTC}^{A}_{a,b}$	NTC between balancing areas a and b (MW)
$\mathrm{NTC}^{R}_{r,s}$	NTC between balancing regions r and s (MW)
K	reserve contribution factor from a thermal/hydro unit
Z	share of NTC between balancing regions set aside for reserve exchange
$Y^{\uparrow/\downarrow}$	share of upward and downward FRR requirement that must be procured from own balancing region

Variables

$\delta_{a,g,\tau,t}$	online status of thermal unit g in area a at $t, \in \{0, 1\}$
$u_{a,g,\tau,t}$	=1 if thermal unit g in area a is started up at $t, = 0$ otherwise
$p_{a,g,\tau,t}$	output of each thermal unit g in area a at t (MW h/h)
$r^{\uparrow}_{a,g,\tau}, r^{\downarrow}_{a,g,\tau}$	procured upward and downward FRR from thermal unit g in area a for planning period τ (MW)
$r^{\uparrow}_{a,h,\tau}, r^{\downarrow}_{a,h,\tau}$	procured upward and downward FRR from hydro unit h in area a for planning period τ (MW)
$rp^{\uparrow}_{a,\tau}, rp^{\downarrow\tau}_{a}$	upward and downward FRR capacity procured in area a in τ (MW)
$trA^{\uparrow}_{a,b,\tau}, trA^{\downarrow}_{a,b,\tau}$	upward and downward FRR exchange from area a to b for planning period τ (positive is export) (MW)
$trR^{\uparrow}_{r,s,\tau}, trR^{\downarrow}_{r,s,\tau}$	upward and downward FRR exchange from region r to s for planning period τ (positive is export) (MW)
$p_{a,h,\tau,t}$	output of each hydro unit h in area a at t (MW h/h)
$p^{st}_{a,h,\tau,t}$	component of the hydro output of unit h in area a at t from the storable inflow (MW h/h)
$p^{ns}_{a,h,\tau,t}$	component of the hydro output of unit h in area a at t from the non-storable inflow (MW h/h)
$p^{s}_{a,\tau,t}$	solar power output in area a at t (MW h/h)
$p^{w}_{a,\tau,t}$	wind power output in area a at t (MW h/h)
$p^{cur}_{a,\tau,t}$	load curtailed in area a at t (MW h/h)
$L_{a,h,\tau}$	level of reservoir associated with unit h in area a at the end of planning period τ (MW h)
$Of_{a,h,\tau}$	spillage (overflow) from reservoir associated with h in area a in planning period τ (MW h/h)
$ep^{A}_{a,b,\tau,t}$	energy exchange from area a to b at t (positive is export from a) (MW h/h)
$ep^{R}_{r,s,\tau,t}$	energy exchange from region r to region s at t (positive is export from a) (MW h/h)

in the system to counteract imbalances. The European Network of Transmission System Operators for Electricity (ENTSO-E), defines three types of operating reserves[1] [9,10].

- Frequency containment reserves (FCR) – operating reserves deployed between 2 and 20 s to counteract frequency change due to sudden imbalance in the system. These reserves are also known as primary control reserves in the Central European system and frequency controlled normal and disturbance reserves in the Nordic system [11].
- Frequency restoration reserves (FRR) – operating reserves activated to restore the system frequency to nominal value and which are deployed to replace the FCR. These reserves are activated between 30 s and 15 min. In the Nordic system, they are called fast active disturbance reserves (FADR) and have until recently been manually activated. In the Central European system these types of reserves are automatically deployed and are called secondary reserves.
- Replacement reserves (RR) – these reserves are used to release already activated FCR and FRR. They are manually activated and called tertiary reserves in the Central European system but are not used in the Nordic system.

Given the progress towards a common day-ahead market in Europe, a natural next step would be the integration of the reserve procurement and balancing markets in Europe. A notable progress

[1] The definitions are rather specific for the European power systems, and comparison with practices in the US is difficult due to quite different market solutions.

was made by the Grid Control Cooperation (GCC),[2] where by March 2010 four of the German TSOs established a common platform for reserve procurement and real-time balancing [12]. As of 2012 GCC expanded to the surrounding control areas forming International Grid Control Cooperation (IGCC), where the respective TSOs of Denmark, the Netherlands, Switzerland, Czech Republic, and Belgium are the members. IGCC is an inter-TSO cooperation aimed to prevent counteracting FRR activation in different control blocks by real-time netting of imbalances using the remaining available transmission capacity (ATC) [13]. Currently, reserve procurement in the IGCC members outside Germany is done separately. Similarly, in the Nordic system, a common regulating power market has been in place since 2002. The reserve procurement, however, is done separately by each of the Nordic TSOs [14].

In this work, we will investigate the impact of a common market for FRR procurement in the Northern European countries (Nordic countries + Germany and the Netherlands). A common reserve market offers economic benefit by increasing the sharing of balancing resources within the region and the reduction of required balancing actions by centralized activation of shared reserves [9]. The relatively cheaper and flexible Nordic hydro resources, with big reservoirs and good ramping ability, could play a pivotal role as a source of balancing services in this region. Although many research works have asserted this idea [15–18,12,19], the modeling approaches they follow are different from the existing electricity markets. Earlier work [18], considered an integrated day-ahead and reserve procurement market clearance for future scenarios. This results in optimal allocation of energy and reserves as well as implicit transmission capacity allocation for reserves exchange. In the current Northern European power markets, however, reserves are contracted for a given period of time and cleared before the day-ahead market, based on the winning bids. Besides, there is no cross-border reserve[3] procurement. We model similar to the reserve procurement approach in current practices and apply it to the Northern European system. The results are compared for different shares of transmission capacity reservation between balancing regions for reserve exchange. The model is based on hourly spot price forecasts to determine the reserve bids, and reserves are procured before the day-ahead market clearance.

The paper is structured in the following order. First, the model is described in Section 3 by presenting the mathematical formulations. Then, the input parameters to the model and the underlying consideration are discussed in Section 4. In Section 5, the case study considered for this work is discussed and the modeling is verified with a set of benchmark results. Finally, the findings of this work are discussed and concluding remarks presented in Sections 6 and 7 respectively.

Model description

A multi-region FRR procurement model is developed and applied to the Northern European countries and an analysis is conducted with respect to the impact of transmission capacity reservation between balancing regions for FRR exchange. We consider that there is a common day-ahead market in the system under consideration, *i.e.* exchange of energy between balancing regions is possible if there is available transmission capacity. A balancing area represents a geographical area whose production–consumption balance is taken care of by a transmission system operator. A balancing region, on the other hand, can consist of several balancing areas [16] (*cf.* these terms defined in the context of Northern Europe in Fig. 6). The model is developed on GAMSIDE[4] using the CPLEX solver[5] and comprises three successive optimization blocks (see Fig. 1), each of them based on mixed integer programming (MIP). The first block is the FRR bidding block. In this block, FRR providing units determine their bidding volumes and bidding prices for the provision of upward and downward FRR based on the spot price forecast. The second block is FRR procurement block; where the bids are aggregated on a common Merit Order List (MOL) and all selected units stay online throughout the planning period, τ, while the marginal unit sets the respective FRR price. In this block, allocation of transmission capacity for the exchange of FRR between balancing regions is taken into account. The third block is the day-ahead market clearance. This block receives the online status of units providing FRR and volume of reserves of the selected units from the reserve procurement block and clears the day-ahead dispatch by reducing the net transmission capacity (NTC) with the capacity reserved for FRR exchange. Online status of FRR providing units at the end of the planning period is then fed-back to the bidding block. The resolution of the day-market is $t = 1$ h and the planning period, for the bidding and FRR procurement blocks, is $\tau = 24$ h, minimum of the planning period lengths, reported in Table 1.

Three types of generating units are identified:

- *Base load units* – Units that only supply base load and do not provide FRR: Nuclear plant, lignite coal.
- *Regulating units* – Units that can provide FRR: Hydro, oil, gas, and hard coal units.
- *Non-dispatchable units* – Units that do not provide reserves: Wind, solar, Run of River hydro (ROR), and other renewable resources.

Bidding block

The bid prices for upward and downward FRR are determined on the basis of the opportunity cost for units in the day-ahead market. For a given planning period each producer determines the bidding prices for FRR based on spot price forecast, $SP_{a,\tau,t}$, for each hour within a planning period in its balancing area. Many approaches are proposed, in literature, on how to make the day-ahead spot price forecasts. For instance, Pousinho et al. [20] propose an approach based on the combination of particle swarm optimization and adaptive-network based fuzzy inference system. On the other hand, Vilar et al. [21], propose methods based on using nonparametric regression techniques with functional explanatory data and a semi-functional partial linear model to forecast the day-ahead prices. In this work, the spot price forecasts are determined based on a simultaneous market clearance (day-ahead and FRR procurement) where the FRR requirements are taken as constraint. For the spot price forecast, a 24 h ahead wind forecast is used. A producer is ready to provide FRR given that they are compensated for the foregone opportunity to profit in the day-ahead market. Eqs. (1)–(6) detail the procedure of determining bidding prices and volumes for a reserve providing thermal unit.

Thermal units

Hard coal, oil, and gas fired power plants can provide FRR, hence we describe them as regulating thermal units. We follow a three case approach where each unit tries to maximize its profit for a given planning period, τ. In the first case, the unit tries to maximize its profit within the planning period without any reserve provision. In the second case, the unit provides only upward FRR. In the third

[2] The cooperation was implemented in four steps starting from the simplest imbalance netting.

[3] Reserves in this paper refer to FRR.

[4] http://www.gams.com/default.htm.

[5] http://www-01.ibm.com/software/commerce/optimization/cplex-optimizer.

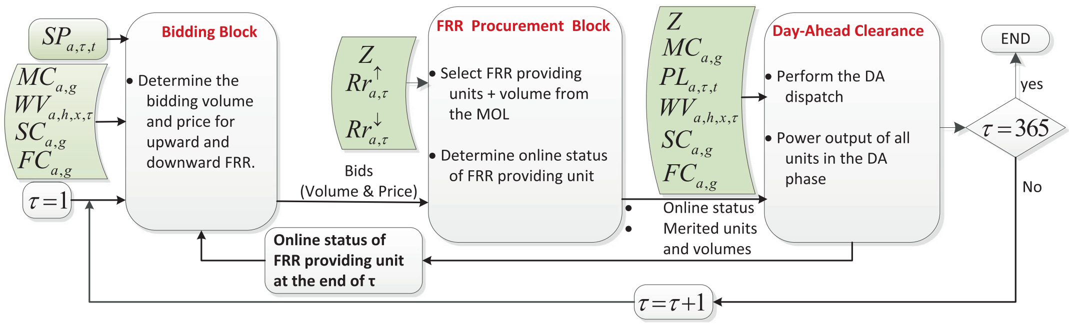

Fig. 1. Model description (only major inputs to each block shown).

Table 1
FRR requirement and planning period for FRR procurement in Northern European countries: NO-Norway, SE-Sweden, DK-W-Western Denmark, DK-E-Eastern Denmark, FI-Finland, DE-Germany, NL-Netherlands.

Country	Planning periodτ	2010 FRR req. up/down (MW)	Comments
DE	One week	2400/2045	Via a common internet platform of the 4 German TSOs, the publication of tenders, the completion of tender submissions and the bidder information about acceptance of bids and/or refusals are announced [36]
NL	One year	300/300	Yearly bilateral contracts between supplier and the TSO [37]
DK-W	One month	262/262	The TSO (Energinet.dk) buys these reserves as a combined, symmetrical reserve for upward and downward regulation [38]
DK-E	One day	262/262	Energinet.dk purchases these reserves in collaboration with the Swedish TSO (Svenska Kraftnät) as a symmetrical product for up and downward FRR [38]
NO	One week	1200/1200	Statnett runs the Reserve Options Market (ROM) to procure FRR in Norway. This market is mainly active during winter months (October to April) [39]
SE	One year	1220/1220	Svenska Kraftnät procures reserves annually based on bilateral contract with suppliers [16,24]
FI	One year	865/865	Finnish TSO (Finngrid) has competitive bidding for capacity in the annual market and hourly market for supplementary procurement once a day if needed [16]

case, the unit provides both upward and downward FRR. A given share of the difference between maximum and minimum generation capacity, K, of each thermal unit is taken as the maximum bidding volume. This value should at least correspond to the value a unit can ramp in 15 min. The time requirement is according to the ENTSO-E network code on load–frequency control which states that FRR should be fully activated within 15 min [22]. Since, different regulating thermal units have varying ramping capabilities, an average value of $K = 0.2$ is taken, (*cf.* [23]). For each case, the revenue for the unit comes from the sale of energy in the spot market; and the fuel cost, the start up cost, and fixed cost of the unit when running account for the cost of the unit. Fig. 2 shows the linearized cost approximation of a thermal unit [24,25]. Thermal units are represented with a constant marginal cost and a fixed cost.

- *case 1*: With no commitment to offer reserves,

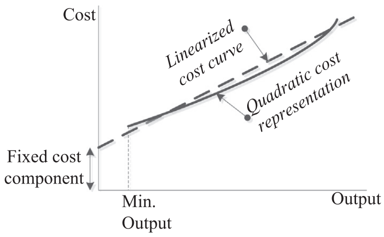

Fig. 2. Linearized cost representation of thermal unit.

$$\overline{R}^{\uparrow}_{a,g} = \overline{R}^{\downarrow}_{a,g} = 0, \quad \forall g \in G_R$$

- *case 2*: With the unit committed to offer only upward FRR,

$$\overline{R}^{\uparrow}_{a,g} = K * (\overline{P}_{a,g} - \underline{P}_{a,g}), \overline{R}^{\downarrow}_{a,g} = 0, \quad \forall g \in G_R$$

- *case 3*: With the unit committed to offer both upward and downward FRR,

$$\overline{R}^{\uparrow}_{a,g} = \overline{R}^{\downarrow}_{a,g} = K * (\overline{P}_{a,g} - \underline{P}_{a,g}), \quad \forall g \in G_R$$

The objective functions for the three cases considered are shown in (1) and the set of constraints in (2)–(4).

Objective function:
$\forall g \in G_R, a \in A, \tau \in \Gamma, i \in \{1,2,3\}$

$$\max \sum_{t \in T} \left\{ p^i_{a,g,\tau,t} * (\mathrm{SP}_{a,\tau,t} - \mathrm{MC}_{a,g}) - \delta_{a,g,\tau,t} * \mathrm{FC}_{a,g} - u_{a,g,\tau,t} * \mathrm{SC}_{a,g} \right\} \tag{1}$$

The i in $p^i_{a,g,\tau,t}$ takes 1, 2, or 3 corresponding to the respective case considered.

Subject to:
$\forall a \in A, g \in G_R, \tau \in \Gamma, t \in T$

$$p^i_{a,g,\tau,t} \leqslant \delta_{a,g,\tau,t} * \overline{P}_{a,g} - \overline{R}^{\uparrow}_{a,g} \tag{2}$$

$$p^i_{a,g,\tau,t} \geqslant \delta_{a,g,\tau,t} * \underline{P}_{a,g} + \overline{R}^{\downarrow}_{a,g} \tag{3}$$

$$u_{a,g,\tau,t} \geqslant \delta_{a,g,\tau,t} - \delta_{a,g,\tau,t-1} \tag{4}$$

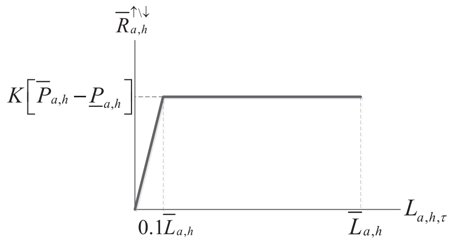

Fig. 3. Reservoir level, $L_{a,h,\tau}$, vs. maximum FRR provision from hydro unit.

The purpose of solving this problem is to find the opportunity cost of withholding generation capacity from the spot market for reserve provision. For *case 1*, the reserve volume is zero, and the whole capacity can be used in the spot market. For *case 2*, some capacity is reserved for upward regulation reserves, and therefore less can be used to earn profits in the spot market. For *case 3*, capacity is reserved for both upward and downward regulation reserves, reducing the revenue in the spot market even further. The decrease in the respective revenues between the first two cases and the last two cases represents the corresponding cost of providing upward and downward FRR respectively.[6] Dividing the costs with the maximum offer for upward and downward FRR gives the respective bidding prices for each unit in the planning period.

Given that B_1, B_2, and B_3 represent the profit for each respective case of a unit, (5) and (6) determine the upward and downward FRR bidding prices respectively.

$\forall a \in A, g \in G_R, \tau \in \Gamma$

$$c^{\uparrow}_{a,g,\tau} = [B_1 - B_2] * \frac{1}{\overline{R}^{\uparrow}_{a,g}} \tag{5}$$

$$c^{\downarrow}_{a,g,\tau} = [B_2 - B_3] * \frac{1}{\overline{R}^{\downarrow}_{a,g}} \tag{6}$$

Hydro units

The methodology for hydro units follows a similar formulation as FRR providing thermal units with the following differences:

- The minimum hydro output from a unit, $\underline{P}_{a,h}$, is considered zero. Because of their fast startup, hydro units can provide FRR without being started up. Besides there is no fixed cost component for hydro units.
- The marginal cost of hydro units are represented by their water values, $WV_{a,h,x,\tau}$. The water value is dependent on the reservoir level, $L_{a,h,\tau}$, and the period, τ. Hence, it has to be updated for each planning period.
- Since FRR procurement is performed prior to the day-ahead clearance, the bidding volume is constrained to avoid draining the reservoir when the level gets lower than 10% of the maximum capacity.[7] This is done in accordance to Fig. 3, where:

$$\overline{R}^{\uparrow\setminus\downarrow}_{a,h,\tau} = \begin{cases} K * (\overline{P}_{a,h} - \underline{P}_{a,h}) & \text{if } L_{a,h,\tau} \geqslant \frac{\overline{L}_{a,h}}{10} \\ 10K\frac{L_{a,h,\tau}}{\overline{L}_{a,h}} * (\overline{P}_{a,h} - \underline{P}_{a,h}) & \text{if } L_{a,h,\tau} \leqslant \frac{\overline{L}_{a,h}}{10} \end{cases}$$

By taking the bulleted points into consideration, the bidding price determination for hydro units is similarly evaluated using (1)–(6).

Reserve procurement block

The FRR providing units determine their bidding prices and volumes for upward and downward FRR and send their bids to the TSO.[8] The TSO stacks the bids in a Merit Order List (MOL) and selects the winning bids with the possibility of procuring reserves from other balancing regions. Marginally selected units set the FRR price in their respective balancing areas. Two methods of reserve procurement are considered:

- *Region based FRR procurement* – In this arrangement, it is only possible to procure reserves within ones own balancing region. This is generally inline with the current practice in Northern Europe.
- *Cross-region FRR procurement* – In this arrangement, a given share of the NTC between balancing regions, Z, is reserved for FRR exchange. It is, therefore, possible to procure reserves from other balancing regions if it decreases the total FRR procurement cost. The main assumption taken here is that certain aspects of the FRR procurement market in the balancing regions, such as reserve procurement mechanisms, pricing mechanisms, and FRR procurement contract periods are harmonized [26]. According to ENTSO-E [9] and Agency for the Cooperation of Energy Regulators (ACER) [27], reservation, on both DC and AC links, should only be allowed if it renders an increase in social welfare.

Units selected to provide FRR must stay online throughout the planning period, $\tau = 24$ h. In both of the FRR procurement arrangements considered, the day-ahead market is integrated and power exchange between any connected areas is possible as long as there is available transmission capacity.

The TSO's objective in this phase is to minimize the reserve procurement cost within the planning period. The objective function is shown in (7) and the set of constraints are presented in (8)–(19).

Objective function:

$\forall \tau \in \Gamma$

$$\min \sum_{a \in A} \left[\sum_{\substack{g \in G_a \\ \cap \\ g \in G_R}} \left\{ r^{\uparrow}_{a,g,\tau} * c^{\uparrow}_{a,g,\tau} + r^{\downarrow}_{a,g,\tau} * c^{\downarrow}_{a,g,\tau} \right\} + \sum_{h \in H_a} \left\{ r^{\uparrow}_{a,h,\tau} * c^{\uparrow}_{a,h,\tau} + r^{\downarrow}_{a,h,\tau} * c^{\downarrow}_{a,h,\tau} \right\} \right] \tag{7}$$

Subject to:

$\forall a \in A, \tau \in \Gamma$

$$rp^{\uparrow}_{a,\tau} = \sum_{\substack{g \in G_a \\ \cap \\ g \in G_R}} r^{\uparrow}_{a,g,\tau} + \sum_{h \in H} r^{\uparrow}_{a,h,\tau} \tag{8}$$

$$rp^{\downarrow}_{a,\tau} = \sum_{\substack{g \in G_a \\ \cap \\ g \in G_R}} r^{\downarrow}_{a,g,\tau} + \sum_{h \in H} r^{\downarrow}_{a,h,\tau} \tag{9}$$

Eqs. (8) and (9) dictate that, for each planning period, the total procured reserves in a given balancing area should be provided by regulating thermal and hydro units. The reserve exchange between regions r and s is given as the sum of reserve exchange between areas located in the regions and is shown in (10) and (11).

$\forall r, s \in R, \tau \in \Gamma$

$$\sum_{a \in A_r} \sum_{b \in A_s} trA^{\uparrow}_{a,b,\tau} = trR^{\uparrow}_{r,s,\tau} \tag{10}$$

$$\sum_{a \in A_r} \sum_{b \in A_s} trA^{\downarrow}_{a,b,\tau} = trR^{\downarrow}_{r,s,\tau} \tag{11}$$

The condition that total upward and downward FRR procured in a

[6] The present order is chosen, as the sole reservation of downward reserves tends to be at zero costs. However, if upward reserves are procured at the same time, there normally is a higher cost for downward reserves too. Thus, the marginal costs of providing downward reserves are calculated from the difference of the second and third case.

[7] In the Norwegian system this only happens occasionally during short periods before the snow melting in the spring in a dry year.

[8] By TSO we assume a super TSO responsible for the balance in the whole system.

given balancing region reduced by the export of reserves to other regions should equal to the reserve requirement in the region is given by (12) and (13) respectively.

$\forall r \in R, \tau \in \Gamma$

$$\sum_{a \in A_r} rp^{\uparrow}_{a,\tau} - \sum_{a \in A_r} \sum_{b \notin A_r} trA^{\uparrow}_{a,b,\tau} \geqslant \sum_{a \in A_r} Rr^{\uparrow}_{a,\tau} \tag{12}$$

$$\sum_{a \in A_r} rp^{\downarrow}_{a,\tau} - \sum_{a \in A_r} \sum_{b \notin A_r} trA^{\downarrow}_{a,b,\tau} \geqslant \sum_{a \in A_r} Rr^{\downarrow}_{a,\tau}, \tag{13}$$

The contribution for upward and downward FRR provision from a regulating thermal unit should not exceed the maximum limit. This condition is shown in (14) and (15) for upward and downward FRR respectively.

$\forall a \in A, g \in G_R, \tau \in \Gamma$

$$r^{\uparrow}_{a,g,\tau} \leqslant \overline{R}^{\uparrow}_{a,g} \tag{14}$$

$$r^{\downarrow}_{a,g,\tau} \leqslant \overline{R}^{\downarrow}_{a,g} \tag{15}$$

Eqs. (16) and (17) ensure that the FRR exchange between balancing regions stays within the limit of the share of NTC reserved for upward and downward FRR exchange respectively.

$\forall r, s \in R, \tau \in \Gamma$

$$-Z * \mathrm{NTC}^R_{s,r} \leqslant trR^{\uparrow}_{r,s,\tau} \leqslant Z * \mathrm{NTC}^R_{r,s} \tag{16}$$

$$trR^{\downarrow}_{r,s,\tau} \leqslant Z * \mathrm{NTC}^R_{r,s} + trR^{\uparrow}_{r,s,\tau} \tag{17}$$

The last two equations in this section, (18) and (19), are added to guarantee that at least $Y^{\uparrow}, Y^{\downarrow}$ of the required upward and downward FRR should come from ones own balancing area, respectively.

$\forall a \in A, \tau \in \Gamma$

$$rp^{\uparrow}_{a,\tau} \geqslant Y^{\uparrow} * Rr^{\uparrow}_{a,\tau} \tag{18}$$

$$rp^{\downarrow}_{a,\tau} \geqslant Y^{\downarrow} * Rr^{\downarrow}_{a,\tau} \tag{19}$$

The dual values of the reserve balance represent the respective reserve prices and the value of the objective function gives the reserve procurement cost.

Day-ahead market block

In this block, the day-ahead market is cleared. This block gets the online status of FRR providing units, procured volume of upward and downward FRR, $r^{\uparrow/\downarrow}_{a,g,\tau}$ and $r^{\uparrow/\downarrow}_{a,h,\tau}$, from the reserve procurement block. For wind, 3 h ahead forecasts are used.[9] It then minimizes the total day-ahead cost for the planning period (*cf.* (20)). Day-ahead costs are comprised of energy costs of thermal units, startup costs and fixed cost (*cf.* Fig. 2) of thermal units, energy cost of hydro units (due to generation and spillage), and rationing costs (when load is shed). In normal cases, it is assumed that there is adequate supply to fulfill the demand. If this does not happen, load is curtailed at a very hight price, VLL, to meet the demand–supply balance. In this model, it is assumed that the day-ahead market is integrated for the considered system, resembling the current state, and that cross-border energy exchange is allowed as long as there is free transmission capacity. Eqs. (21)–(34) represent the set of constraints for the day-ahead block.

Objective function:

$\forall \tau \in \Gamma$

$$\min \sum_{a \in A} \left\{ \sum_{t \in T} \left[\sum_{g \in G_a} \{ p_{a,g,\tau,t} * \mathrm{MC}_{a,g} + u_{a,g,\tau,t} * \mathrm{SC}_{a,g} + \mathrm{FC}_{a,g} * \delta_{a,g,\tau,t} \} \right.\right.$$
$$\left.\left. + p^{cur}_{a,\tau,t} * \mathrm{VLL} \right] + \sum_{h \in H_a} \left(Of_{a,h,\tau} + \sum_{t \in T} p^{st}_{a,h,\tau,t} \right) * WV_{a,h,x,\tau} \right\} \tag{20}$$

Subject to:

$\forall g \in G_R, \tau \in \Gamma, t \in T$

$$p_{a,g,\tau,t} \geqslant \delta_{a,g,\tau,t} * \underline{P}_{a,g} + r^{\downarrow}_{a,g,\tau} \tag{21}$$

$$p_{a,g,\tau,t} \leqslant \delta_{a,g,\tau,t} * \overline{P}_{a,g} - r^{\uparrow}_{a,g,\tau} \tag{22}$$

When generating and standing by for upward FRR and downward FRR, the maximum generation capacity is reduced by $r^{\uparrow}_{a,g,\tau}$ and the minimum generation capacity is increased by $r^{\downarrow}_{a,g,\tau}$. These conditions for reserve providing thermal units are enforced by (21) and (22) respectively. The corresponding conditions for a hydro unit are shown by (23) and (24). It should be noted that $r^{\uparrow/\downarrow}_{a,g,\tau}$ and $r^{\uparrow/\downarrow}_{a,h,\tau}$ are now parameters as their values have been determined in the previous block.

$\forall a \in A, h \in H, \tau \in \Gamma, t \in T$

$$p_{a,h,\tau,t} \geqslant \underline{P}_{a,h} + r^{\downarrow}_{a,h,\tau} \tag{23}$$

$$p_{a,h,\tau,t} \leqslant \overline{P}_{a,h} - r^{\uparrow}_{a,h,\tau} \tag{24}$$

$$p^{ns}_{a,h,\tau,t} + p^{st}_{a,h,\tau,t} = p_{a,h,\tau,t} \tag{25}$$

Eq. (25) defines the generation from a hydro unit to be the sum of output components of storable and non-storable inflow (*cf.* Fig. 4). The total generation from non-storable inflow component of a hydro unit should not exceed the total non-storable inflow in the period (shown in (26)).

$\forall a \in A, h \in H, \tau \in \Gamma$

$$\sum_{t \in T} p^{ns}_{a,h,\tau,t} \leqslant Q^{ns}_{a,h,\tau} \tag{26}$$

Since, base thermal units do not provide FRR, the only restrictions for these units are that a unit can only generate between the minimum and maximum limit when running (*Cf.* (27) and (28)).

$\forall g \in G_B, \tau \in \Gamma, t \in T$

$$p_{a,g,\tau,t} \geqslant \delta_{a,g,\tau,t} * \underline{P}_{a,g} \tag{27}$$

$$p_{a,g,\tau,t} \leqslant \delta_{a,g,\tau,t} * \overline{P}_{a,g} \tag{28}$$

Solar and wind power plants are modeled similarly. The respective generation is aggregated per balancing area. Eqs. (29) and (30) ensure that the outputs should not exceed the solar and wind capacity during the specified hour respectively.

$\forall a \in A, \tau \in \Gamma, t \in T$

$$p^s_{a,\tau,t} \leqslant \overline{P}^s_{a,\tau,t} \tag{29}$$

$$p^w_{a,\tau,t} \leqslant \overline{P}^w_{a,\tau,t} \tag{30}$$

The load balance in a given hour is defined in (31). It dictates that the total generation from all units (thermal, hydro, and RES) in a given area reduced by the export to other areas added with the energy curtailed should equal to the load level in the area during the specified hour t. The dual value of the load balance equation represents the spot price.

$\forall a \in A, \tau \in \Gamma, t \in T$

[9] The fact that the day-ahead market being cleared 24 h ahead, the choice of 3 h ahead wind forecast might seem out of place; but the following points justify the choice.

- Since the resolution of the FRR procurement is 24 h and relies on the spot price forecasts made 24 h ahead, we wanted to have a different wind forecast in the day-ahead market clearance. This is necessary as in reality, the spot price forecasts are different from the actual spot prices.
- The intraday market is not considered in this formulation. Thus, taking 3 h ahead wind forecasts for the day-ahead market clearance results in better price signals than 24 h ahead wind forecasts as this emulates the portfolio adjustment by producers in the intraday period. This is due to the fact that wind forecast errors are among the reasons for the portfolio adjustment.

$$\mathrm{PL}_{a,\tau,t} = \sum_{g\in G_a} p_{a,g,\tau,t} + \sum_{h\in H_a} p_{a,h,\tau,t} + p^{s}_{a,\tau,t} + p^{w}_{a,\tau,t} - \sum_{b\in A} ep^{A}_{a,b,\tau,t} + p^{cur}_{a,\tau,t} \quad (31)$$

The power exchange between regions r and s at a given time period t is the sum of power exchanges between areas located in the respective regions, as described in (32).

$$\sum_{a\in A_r}\sum_{b\in A_s} ep^{A}_{a,b,\tau,t} = ep^{R}_{r,s,\tau,t}, \quad \forall r,s \in R, \tau \in \Gamma, t \in T \quad (32)$$

Equations related to hydropower reservoirs are represented by (33) and (34). The reservoir balance at the end of a planning period τ equals previous period reservoir level plus the storable inflow reduced by total hydro generation minus the total hydro spillage in the planning period (*cf.* (33)). Eq. (34) on the other hand ensures that the reservoir level does not go above the maximum reservoir level.

$\forall a \in A, h \in H, \tau \in \Gamma$

$$L_{a,h,\tau} = L_{a,h,\tau-1} + Q^{st}_{a,h,\tau} - \sum_{t\in\tau} p^{st}_{a,h,\tau,t} - Of_{a,h,\tau} \quad (33)$$

$$L_{a,h,\tau} \leqslant \overline{L}_{a,h} \quad (34)$$

Inputs to the model

The model is implemented as a fundamental model of the Northern European power system. The objective of the optimization model is the minimization of the total operation costs, given the demand and reserve requirements. The inputs to the model include generating units, the transmission as well as the demand in the power system, described in the following subsections.

Generation units

Generation units are classified as base-load units (nuclear and coal plants), FRR providing units (hydro, oil, and gas fired power plants), and non-dispatchable units (wind, run of river (ROR) hydro, and solar power plants).

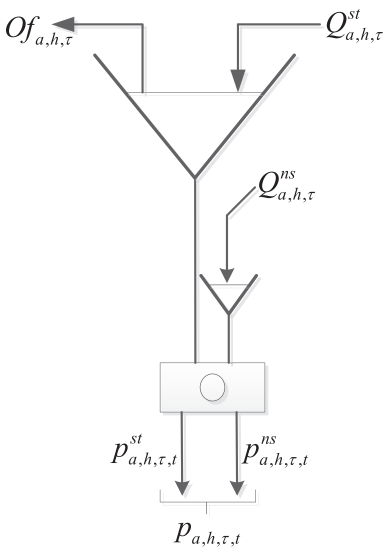

Fig. 4. Hydro power generation representation.

Hydropower units

Hydropower units are represented as in Fig. 4. Hydropower systems may have quite complex topologies with many cascaded reservoirs and power plants in the same rivers system. The reservoirs may have different storage capacity with significant water travel time that couples the decisions between several time steps [28]. For this work, a simplified and aggregated reservoir representation obtained from the EMPS model[10] [30] is used. Each balancing area contains one or more aggregated hydro reservoirs, where each hydro unit is connected to a respective reservoir as in Fig. 4.

In a given planning period, the marginal cost for hydro units is given by the water value [30]. As there is no significant production cost for hydro power, but rather limited amount of water available, water value refers to the opportunity cost of storing reservoir water for future utilization. These values are dependent on the time of the year and the reservoir level (*cf.* Fig. 5).

Thermal units

As explained in the beginning of Section 3, thermal units based on oil, gas, and hard coal are regulating thermal units. These types of units are characterized by the ability to sufficiently ramp up or down within 15 min. On the other hand, thermal units based on Nuclear and lignite coal tend to generate at their nominal operating point and require long time to startup and are used as base load thermal units. Their cheaper marginal cost compared to regulating thermal plants makes them useful for long period, non-stop operation.

Non-dispatchable units

Units whose outputs are difficult or impossible to control are referred to as non-dispatchable. The availability of these resources depends on the weather conditions.[11] We might opt to decrease the output by curtailing the production at a given time but it is not possible to obtain more output than given by the weather conditions. Solar, wind, ROR hydro are the resources considered in this work that fall into this category. These resources are characterized by zero marginal production cost and will be prioritized in the day-ahead Merit Order List (MOL) and will be fully utilized provided that there are no bottlenecks in the system. Even though there are reports of utilizing wind farms to provide downward regulation (for example see Ref. [31]), no FRR provision from these resources is considered in this work.

Transmission capacity

One of the main objectives of this work is to assess the effect of transmission capacity reservation between balancing regions for reserves exchange. The NTC between balancing areas or balancing regions are used as the value of transmission capacity in the computations. As per ENTSO-E[12] definition, NTC refers to the maximum total exchange between two connected power systems available for commercial purposes, for a certain period and direction of active power flow [33].

Reserve requirement

FRR, also called secondary reserves in the Central European system and Frequency Disturbance Reserves in the Nordic system, are

[10] EMPS refers to EFIs Multi-area Power-Market Simulator and is developed by SINTEF Energy Research for long term hydro power planning [29].

[11] Weather condition in this context means solar radiation for pv plants, wind speed for wind farms, non-storable inflow for ROR hydro plant.

[12] An acronym for European Network of Transmission System Operators for Electricity, ENTSO-E represents all electric TSOs in the EU and others connected to their networks, for all regions, and for all their technical and market issues [32].

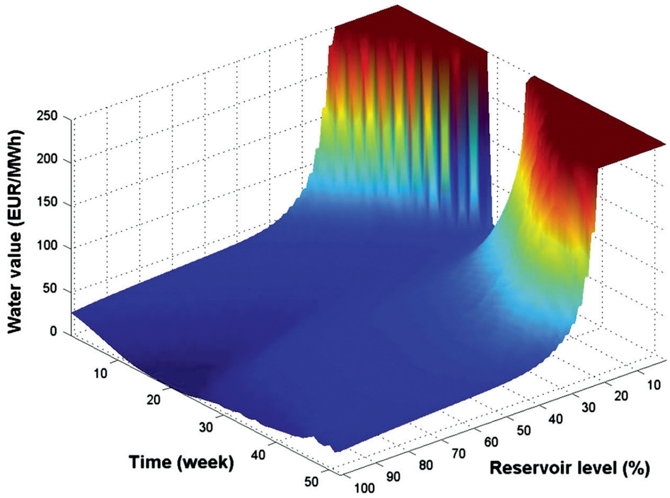

Fig. 5. Water value plot for a reservoir in South Norway as obtained from EMPS (truncated at 250 EUR/MW h). It can be seen that the water value is generally high when the reservoir level is low and low when the reservoir is full. Similarly, for a given reservoir level, we can see that the water value is low during high inflow period (late spring and summer – weeks 20–35) and high during low inflow period.

types of operating reserves activated to restore the system frequency to nominal value and are deployed to replace the primary reserves [10]. The FRR requirement for a given balancing area or country is defined by the respective authorities. The required FRR capacity in a given region mainly depends on the load [11]. The increasing wind power integration in the European power system and the subsequent increase in system imbalances, however, is expected to increase the operating reserve requirement [5,34]. The TSOs make sure that the required reserves are in place for their respective planning periods[13] (the time span where reserves are contracted for). In the current market arrangement in Northern European countries, the planning periods are different (see Table 1). For this work, because of the underlying assumption of harmonized cross-border reserve procurement, we assume that the planning period is the same for all of the countries. Thus, $\tau = 24$ h, the minimum of all areas shown in Table 1. Since, a unit providing FRR has to stay online for the duration of the planning period, considering longer periods exacerbate the sub-optimal solutions due to the electricity market clearance sequence. Moreover, reserve requirement per area is constant for all planning periods.

Case study

We consider the Northern European power system in its state of 2010, shown in Fig. 6. Three balancing regions are modeled: the Nordic system, Germany, and the Netherlands. The Nordic system contains Norway, Sweden, Finland, and Denmark.[14] Germany is divided into 4 balancing areas, representing the 4 German TSO areas. The Netherlands is considered as one balancing area. Norway, Sweden, Finland, and Denmark are divided into 5, 4, 1, and 2 balancing areas respectively. The division in the Nordic system is according to the Elspot price area division [40]. For the Nordic system we consider 49 aggregated reservoirs, with an aggregated hydro unit connected to a reservoir (*cf.* Fig. 4). For reliability purposes, 2/3 of the required reserves should be procured from ones own balancing area [41], *i.e* $Y^{\uparrow/\downarrow} = 2/3$.

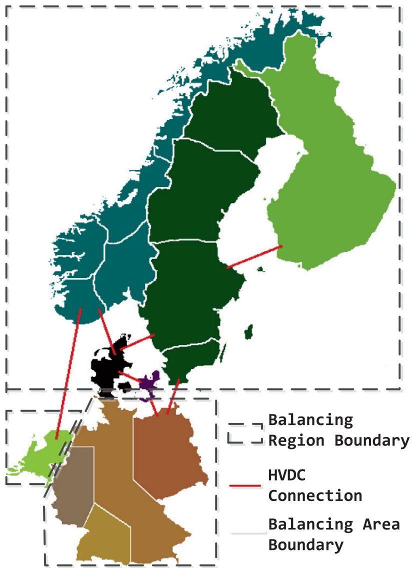

Fig. 6. Northern European system in 2010.

Installed generation capacity in 2010 is considered. Generation capacity and peak demand per country is shown in Table 2. Data for thermal generation units is taken from [16]. Thermal units are represented with a constant marginal cost, fixed, and startup costs (*cf.* Fig. 2). Marginal costs of hydropower plants are represented with their respective water values obtained from the EMPS

[13] The provision of voluntary balancing reserves based only on the incentives of the real-time balancing market could sometimes be insufficient. Hence, steps to make sure that sufficient balancing reserves are available in the system are necessary (*cf.* [35] for the case in Norway).

[14] It should be noted that in the real system, West Denmark is synchronous with the Central European system and East Denmark is synchronous with the Nordic System. For this work, however, the whole Danish system is considered as part of the Nordic balancing region.

model [30]. Aggregated wind farms per area are modeled with maximum output equal to the available wind power capacity for the given hour. A similar approach is used for solar power production. The wind and solar time series data are obtained from the COSMO EU, which offers a high resolution numerical weather predictions as well as measurements[15] [42]. The NTC between balancing areas and balancing regions for 2010, obtained from ENTSO-E [43], are used as exchange constraints in the optimization.

Results and discussions

In this section, we first analyze the energy exchange between balancing regions in Section 6.1. Following that, we asses how the FRR bidding prices are related to the spot price forecasts and the unit marginal cost (water value in the case of hydro) in Section 6.2. Following this, we assess the relation between the system load, day-ahead cost, and downward FRR procurement cost in Section 6.3. In Section 6.4, the cost implication of NTC reservation for FRR exchange is addressed. Finally, the FRR procurement per country for varying NTC reservation is discussed in Section 6.5.

Energy exchange

Fig. 7 shows the energy export from the Nordic to the Central European system in winter and summer. The flow is predominantly from Nordic to Central European system in summer during daytime on weekdays. This is generally the result of low demand and high inflow in the Nordic system. Lower demand in the Central European system and flexible hydro in the Nordic system make the latter importer of Electric energy during nights and weekends. On the other hand, the flow is generally from the Central European to the Nordic system in the winter due to the need for heating and low hydro inflow in the Nordic system.

Similarly, Fig. 8 shows the sorted annual energy exchange profile from the Nordic region to Germany, Netherlands, Central European system and Germany to Netherlands. It can be seen that the flow direction is predominantly from Nordic system to the Central European system (for about 65% of the time). There is, however, no dominant flow direction between Netherlands and Germany as can be seen from the figure.

FRR bidding prices

The FRR bidding prices in relation to the spot price forecasts and the marginal cost of a thermal unit (analogously, the calculated water value of a hydro unit) are plotted in the following set of figures.

Fig. 9 shows the bidding prices for upward FRR for a hydro unit plotted (solid line left axis) against the water value of the hydro reservoir at the respective period and averaged spot price forecasts over the year (right axes). The thin dashed line shows the daily water value of the reservoir. The average daily spot prices are plotted as the thick dashed line in the figure. Fig. 10 shows the downward FRR bidding price for the hydro unit plotted against the calculated water vales and averaged spot price forecasts.

It can be seen from Figs. 9 and 10 that when the averaged spot prices forecasts are higher than the water value (e.g. days 50–100 in Fig. 9), the upward FRR bidding price is positive and increases with the increase in the difference. Similarly, the downward bidding prices are positive when the water values are higher than the average spot price forecasts (e.g. some days between 150 and 250 in Fig. 10) and the bidding prices become higher when the difference gets higher.

When the average spot price is higher than the water value, the unit tends to produce at maximum capacity where it gets more profit. When it has to standby to provide upward FRR, it has to operate at a lower output level, thus reducing its profit. This loss represents the opportunity cost of providing upward FRR. In this case, the unit is ready to provide downward FRR at a zero price.

When the water value is higher than the average spot price forecasts, the unit does not normally run as it incurs a loss. But, if it has to operate anyway, it tends to operate at the minimum possible operating point to reduce its loss. If it has to provide downward FRR, however, it has to operate at a value higher than the minimum value further increasing the losses. The downward bidding prices, therefore, reflect this cost. It can, however, provide upward FRR for free.

Table 2
Generation capacities and peak demand in Northern Europe in 2010 [MW].

	NO	SE	FI	DK	DE	NL
Thermal	0	15,698	15,382	9020	105,335	24,012
Hydro	28,000	14,966	3000	0	3838	0
Wind	450	2200	300	3785	27200	2500
Solar	0	8	0	11	12,200	85
Peak demand	23,427	27,666	13,780	6784	98,268	17,637

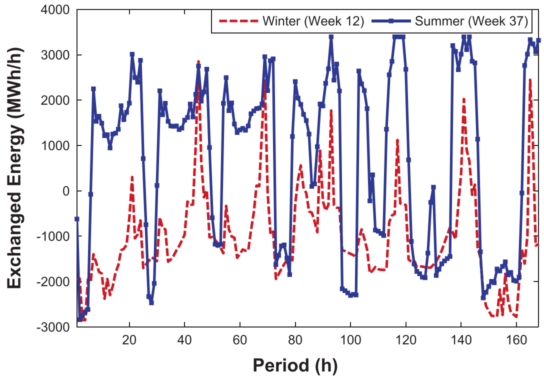

Fig. 7. Energy export from Nordic to Central European system with no reservation of transmission capacity for reserves exchange (negative is import).

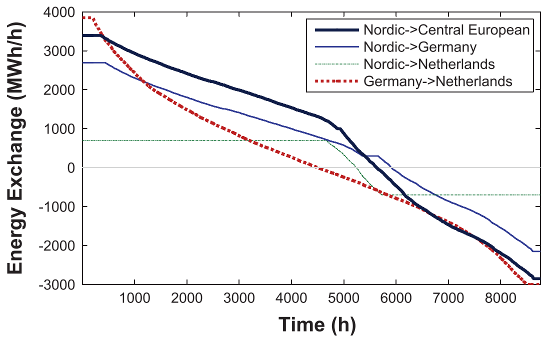

Fig. 8. Annual energy exchange sorted in decreasing order in 2010. (NTC values: Nordic–DE = DE–Nordic = 2695 MW, Nordic–NL = NL–Nordic = 700 MW, NL–DE = 3000 MW, DE–NL = 3850 MW).

[15] The model uses the measured wind speeds and actual geographically distributed installed capacities to calculate the wind power production output. The modeling results are validated using TSO data from Germany (TenneT control area) and Denmark as comparative values in [42].

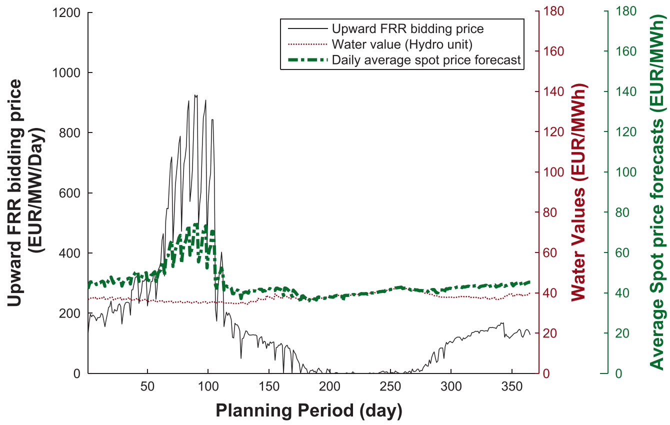

Fig. 9. Upward bidding price vs. spot price forecast for a hydro unit in South Norway.

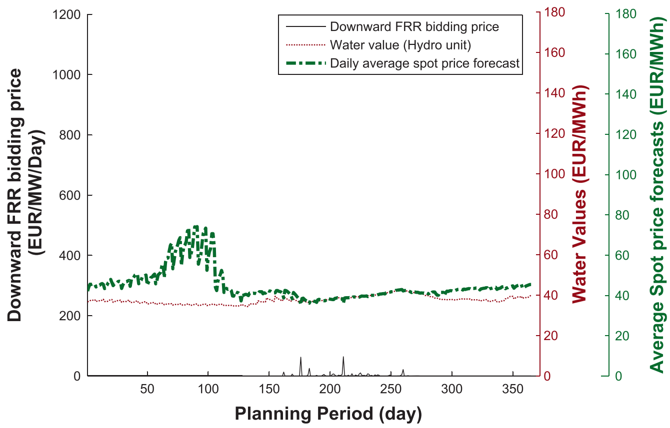

Fig. 10. Downward bidding price vs. spot price forecast for a hydro unit in South Norway.

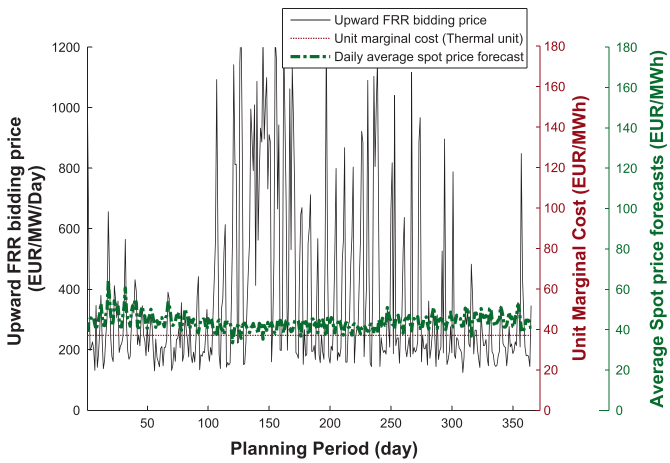

Fig. 11. Upward bidding price vs. spot price forecast for a hard coal thermal unit in Germany.

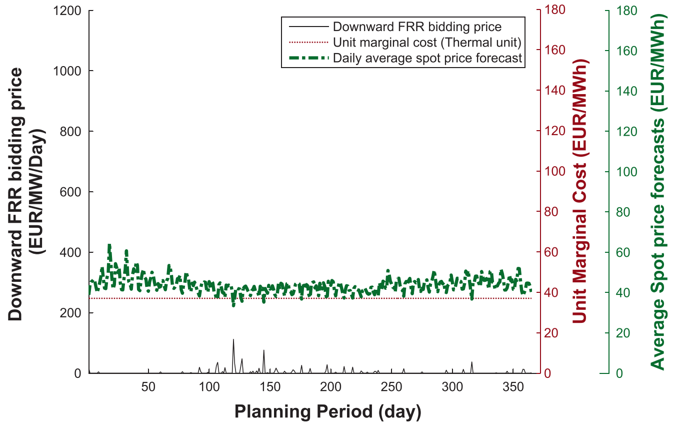

Fig. 12. Downward bidding price vs. spot price forecast for a hard coal thermal unit in Germany.

Similar deductions can be reached for the bidding prices of thermal units, (Figs. 11 and 12) as the bidding prices of a hydro unit above. An interesting difference can be observed, however, on how the bidding prices for thermal and hydro units evolve. The upward bidding price for the thermal unit holds a value different from zero throughout the year. For the hydro unit, the upward bidding prices are zero except for a time span where the reservoir in Norway is at its lowest. This is similar to the observation in reality in the Norwegian system where the RKOM market is active (*cf.* Table 1). Another important observation is that, for both the hydro and thermal unit, the downward bidding prices are zero except during the low demand periods (*cf.* Fig. 13).

Day-ahead and downward FRR procurement costs in relation to system load

As can be seen from Fig. 13, the total day-ahead cost, energy plus startup and fixed costs, (green, solid line in the figure), is highly correlated to the total system load (broken red line). The downward FRR procurement costs (thin, blue line), on the other hand, are high when the day-ahead costs are low and viceversa. When the load is low, fewer units are committed in the day-ahead market. However, some units have to run to solely provide downward FRR reserves, thus, generate at the minimum possible capacity in the day-ahead market. Such units should, therefore, take the loss they encounter in the day-ahead market into consideration when determining the downward FRR prices. This in effect results in higher downward FRR bidding prices, subsequently higher downward FRR procurement cost (*cf.* Figs. 10 and 12).

Cost implication of NTC reservation for reserve exchange

Fig. 14 shows the total cost at different levels of transmission capacity reservation between balancing regions for FRR exchange, *Z*. The total costs are the sum of FRR procurement costs and day-ahead costs. Intuitively, because of the reduced transmission

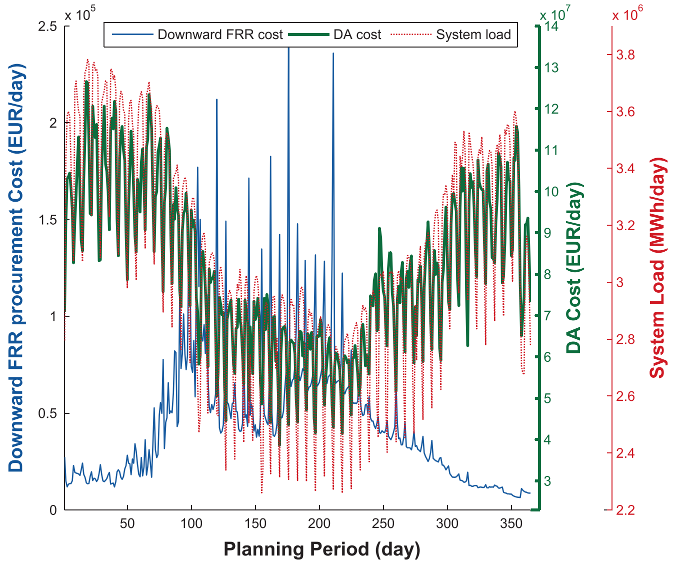

Fig. 13. Day-ahead and downward FRR costs vs. total load in the system.

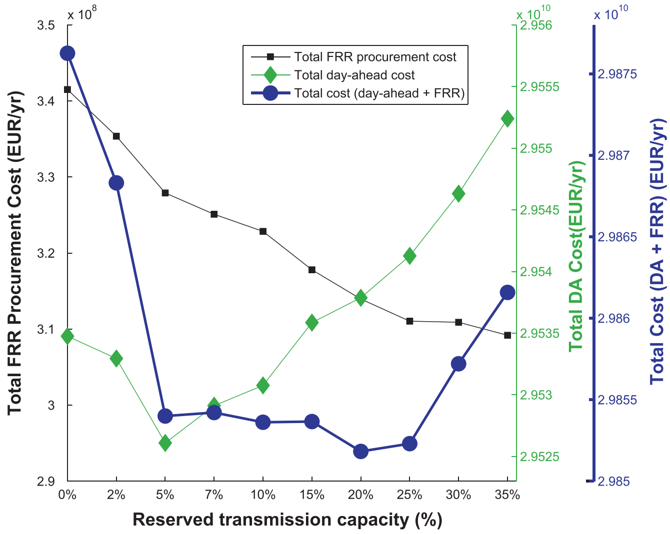

Fig. 14. Annual procurement costs vs. capacity reservation between balancing regions for FRR exchange, *Z*.

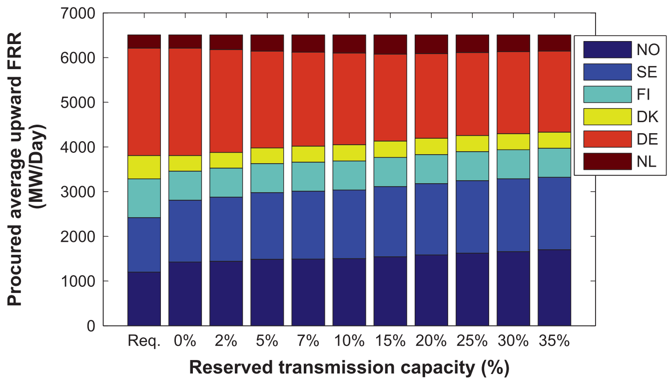

Fig. 15. Upward FRR procured per country for varying transmission capacity reservation vs. the requirement: NO-Norway, SE-Sweden, FI-Finland, DK-Denmark, DE-Germany, NL-Netherlands.

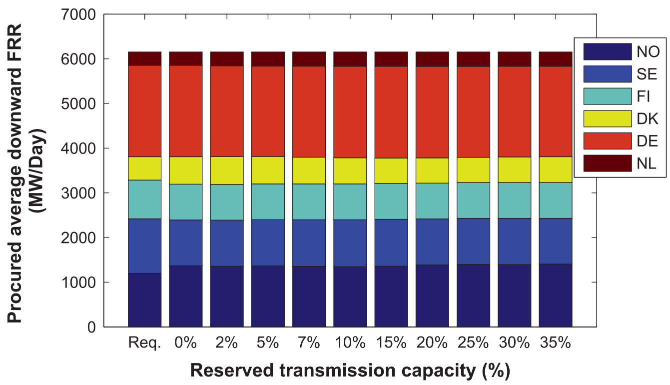

Fig. 16. Downward FRR procured per country for varying transmission capacity reservation vs. the requirement.

capacity for energy exchange the day-ahead costs are expected to be higher when there is transmission capacity reservation for FRR exchange. In this case, however, the day-ahead cost (diamond markers in the figure) decrease until $Z = 5\%$. The reason is the increased flexibility obtained in the FRR importing system for low transmission capacity reservation. We have assumed that the procurement period of the reserves is 24 h which means that units need to be online for 24 h. This leads to high costs of reserves. Allowing for the import of FRR increases the flexibility of the importing system, and thus reduces the day-ahead costs. The day-ahead costs, however, start to pick up for reservation levels above 5%. The FRR procurement costs (square markers) are the highest when there is no possibility of cross-border reserve procurement and decrease with increasing Z. This is as a result of the possibility of cheaper cross-border reserve procurement with increase in Z. As a result, we get a point $Z \approx 20\%$ where the total cost (circular markers in Fig. 14) is the lowest. This reservation results in a saving of EUR 24.5 million per annum. These results seem to contradict the findings in an earlier study [44], where the authors conclude that such reservation is not profitable due to the losses in the day-ahead market. However, the contradiction is not real. The analysis in [44] uses a model with an integrated clearing of the reserve and day-ahead markets. The present model reflects the existing European power markets, with separate markets for reserves and day ahead energy. The present analysis shows that with this market design, reservation of transmission capacity for reserve capacity can be profitable.

Reserve procurement per country

Figs. 15 and 16 show the upward and downward FRR procurement and requirement per country for different levels of transmission capacity reservation. There is an increase in upward reserve procurement from Norway, Sweden, and the Netherlands. On the other hand, the upward FRR procurement from Germany decreases with increase in transmission capacity reservation for FRR exchange (*cf.* Fig. 15). At the least cost transmission reservation point, i.e. $Z = 20\%$, the reserves procured from Norway, Sweden, and the Netherlands are 32%, 31%, and 40% higher compared to the requirement. For the same reservation, Germany procures 21% of the required upward FRR requirement from the Nordic region and Netherlands. In General, for $Z = 20\%$, 10% more upward FRR from the Nordic and 14% less from the DE + NL systems are procured compared to the requirement. It can be observed that for $Z = 0\%$ the reserve procured by a Nordic country is not equal to the requirement. This is because of the possibility of procuring reserves from other balancing areas within ones balancing region.

Similarly, Fig. 16 shows the downward FRR procurement per country for different values of transmission capacity reservation. There is an increase in downward FRR procurement from Norway, Denmark, and Netherlands by 16%, 8%, 8% and a decrease by 16% and 7% from Sweden and Finland respectively compared to the requirement.

Summary and concluding remarks

In this work, we developed a model that follows the temporal hierarchy of the current electricity market arrangements in Northern Europe. We present the mathematical formulation and the principle of bidding price determination by each reserve providing unit, the reserve procurement on different levels of capacity allocation for FRR exchange, and the day-ahead market.

An opportunity cost based method is employed to determine the FRR bidding prices for a unit. At a given time, the difference (the loss in profit) a unit incurs due to its commitment to provide reserves is used as the corresponding cost of standing by to provide the reserves. This cost is eventually used to calculate bidding prices for upward and downward FRR capacity provision.

Reserve providers send their bid volumes and prices for upward and downward FRR and the TSO selects the cheapest bids with the possibility of procuring from other balancing regions if transmission capacity is reserved for this purpose. Reserves are procured for a given planning period which is longer than the resolution in the day-ahead market and selected units should stay online for the whole period.

The day-ahead phase has a resolution of one hour and follows the FRR procurement. The transmission capacity for energy exchange is reduced with the value set aside for FRR exchange. Cost minimization is performed for a period of 24 h.

The bidding prices for both upward and downward FRR from a reserve providing unit are determined by the difference between the daily average spot price forecasts and the unit marginal cost (water value in the case of a hydro unit) at the given day.

The day-ahead and downward FRR procurement costs are positively and negatively correlated to the system load respectively. Therefore, the day-ahead costs are high when the downward reserve procurement costs are low and viceversa.

An interesting result is the fact that the day-ahead costs decrease for small values of the transmission capacity reservation. This is explained by the fact that procuring reserves in another area reduces the need to keep reserves in the expensive system, increasing the flexibility and reducing the day-ahead cost. The FRR procurement costs, on the other hand, steadily decrease with increasing the reserved transmission capacity. The lowest total costs occur in our model for a general transmission capacity reservation level of 20%. With this value, a potential annual saving of EUR 25 million is obtained, compared with the no-reservation case. In these analyses, the same relative capacity reservation was used for all interconnections and kept constant for the whole year. It is expected that having more capacity reservation in some corridors and less in some others could result in greater total cost reduction. The optimal reservation of transmission capacity on individual interconnections will be the focus of further work. At the least cost operation point, 10% more and 14% less upward FRR are procured from the Nordic and Central European systems respectively compared to the requirement.

The scope of this work is limited to FRR procurement and day-ahead market and does not include the real-time balancing market. It is expected that reserving transmission capacity for exchange of balancing energy will result in further cost reduction as a result of imbalance netting and utilization of cheap cross-border resources. This idea will also be addressed in future work.

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Appendix C

Publication III

Y. Gebrekiros, and G. Doorman, *Optimal Transmission Capacity Allocation for Cross-border Exchange of Frequency Restoration Reserves (FRR)*, 18th Power Systems Computation Conference, Wroclaw, Poland, 18-22 August 2014.

Publication III

Is not included due to copyright

Appendix D

Publication IV

Y. Gebrekiros, S. Jaehnert, and G. Doorman, *Sensitivity Analysis of Optimal Transmission Capacity Reservation for Cross-border Exchange of Reserve Capacity in Northern Europe*, 11th International Conference on the European Energy Market (EEM), Krakow, Poland, 28-30 May 2014.

Publication IV

Is not included due to copyright

Appendix E

Publication V

Y. Gebrekiros, G. Doorman, A. Helseth, and T. Preda, *Assessment of PTDF Based Power System Aggregation Schemes*, 2015 Electrical Power and Energy Conference (EPEC), London, ON, Canada, October 26-28, 2015.

Publication V

Assessment of PTDF Based Power System Aggregation Schemes

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***Abstract*—Power flow computations are essential for many types of power system analyses. In order to reduce computation time and reflect actual power market operation, network aggregation principles are often used.**

In this work we discuss network aggregation based on power transfer distribution factors (PTDF), by testing three different aggregation schemes. We analyze the performance of the three schemes comparing their solutions with the results obtained from a DC optimal power flow (DCOPF) performed on the non-aggregated system. The performance is evaluated on the IEEE 30-bus test system using three indicators; power generation, inter-zonal flows, and total system costs.

To account for wind and load forecast uncertainty, we consider a modified IEEE 30-bus system proposed to address massive wind integration. The case study results show that the choice of weighting scheme significantly impacts the results. In particular, the PTDF aggregation schemes based on nodal injections (production minus demand) and production outperform the pro-rata aggregation scheme.

***Index Terms*—DCOPF, Network reduction, PTDF, PTDF aggregation, Wind energy integration**

I. Introduction

To achieve the objectives of the Third Energy Package of the European Union policy, a significant progress is observed towards the realization of an internal electricity market [1]. An initiative launched in 2010, the Central Western European (CWE) coupling, which covers Netherlands, Belgium, France, Germany and Luxembourg, created a single platform for day-ahead electricity trading. Following this, Interim Tight Volume Coupling (ITVC) resulted in increased efficiency of the European power system by coupling the day-ahead market of the CWE region with the Nordic market. And the latest one is the Price Coupling of Regions (PCR); which has been in operation since May 2014 [2]. The project is an initiative of the seven Power Exchanges (PX) covering the electricity markets in Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Italy, Latvia, Lithuania, Luxembourg, the Netherlands, Norway, Poland, Portugal, Spain, Slovenia, Sweden and the UK [3]. One of the key elements of the PCR project is the development of a single price coupling algorithm, which will adopt the name of EUPHEMIA (acronym of Pan-European Hybrid Electricity Market Integration Algorithm) [3]. It will be used to calculate energy allocation and electricity prices across Europe, maximizing the overall welfare and increasing the transparency of the computation of prices and flows. Moreover, there is a significant integration of renewable energy sources in to the European system, which is expected to increase in the near future. In addition, the proposed EU Guideline on Capacity Allocation and Congestion Management (CACM) [4] requires the use of flow-based market coupling (FBMC) [5]–[7] unless in cases where cross-zonal capacity is less interdependent and it can be shown that the flow-based approach brings no added value.

Handling large amounts of power system data for operational and planning purposes is often cumbersome that reduction of the system is needed. This raises the question of how to obtain an aggregated grid representation that closely represents the original system. This paper reviews power flow based grid reduction methods and contributes to this discussion by analyzing PTDF-based aggregation schemes.

The paper is organized as follows. We briefly discuss FBMC and network aggregation methods in Section II and III respectively and go through the mathematical formulation in Section IV. We then present a case study Section in V and discuss the findings in Section VI and windup with concluding remarks in Section VII.

II. Flow-Based Market Coupling (FBMC)

Market coupling refers to the implicit auctioning of physical transmission rights via hourly auctions organized by PXs in the day ahead market [8]. The flow-based analysis is a methodology which describes the network in order to take into account the impacts of cross-border exchanges on network security constraints when optimizing the market flows (i.e. matching of supply and demand) for the concerned region, thus offering more capacity and maximizing the social welfare generated [9].

FBMC, which is based on DCOPF, is expected to result in better utilization of the grid while ensuring a same

Security of Supply (SoS) level as today [10]. Flow-based (FB) computations are expected to improve quality of results compared to NTC[1] based calculations due to the fact that, although linearized, the physics of power flow is represented in the market clearing. However, their ability to improve total welfare heavily depends on the quality of grid models [11], [12]. Based on analysis in the CWE region, Waniek *et al.* [7] show that the FBMC by using PTDFs can improve the efficiency of the coupled markets compared to the NTC method. During the FB experimentation of the CWE TSOs, it was proven that FB capacity calculations are feasible from an operational point of view and increase the capacity offered to the market when compared to NTC based calculations [9].

III. Network Reduction and (or) Aggregation

Long distance power transmission requires the computation of large scale power systems for operational and planning purposes. Dealing with huge amount of data is computationally demanding and reduction of the system is sometimes desirable (e.g. for the flow-based algorithm). Obviously, the nodal to zonal reduction results in loss of accuracy of the grid representation [13]. Based on the specific analysis, Papaemmanouil *et al.* [14] broadly classify network reduction techniques as static and dynamic. In static network reduction, the reduced model represents a snapshot of the system and is suitable for static analysis only. On the other hand, the reduced system is applied for dynamic analysis in the latter. For electricity market analyses the static network reduction methods are applied.

In the standard reduction techniques, the size of a power network is reduced by partitioning the network into a group of internal, external, and boundary buses. An equivalent network is created by deleting the external buses while simultaneously modifying the boundary buses to represent the electrical characteristics of the external buses with the internal network left unchanged. Hence, the equivalent representation models a portion of the network with the original detail while eliminating the remainder of the network [15].

In the OPF based equivalencing techniques, buses are aggregated rather than eliminated. In the PTDF based aggregation, nodal PTDFs are aggregated into zonal PTDFs that give similar inter-zonal flows. In the aggregation process, estimating the nodal injection factor for a given zonal injection is a challenging task as the values are not known and have to be estimated. As a result, many ideas are proposed on how to address this issue (*cf.* Section IV-B). Van den Bergh *et al.* [13] propose a new method to improve aggregated network models by performing the nodal-zonal network reduction separately for different generation type injections. They stress that this method gives a considerable improvement in the grid flow modeling. For an analysis of the Nordic power system, Helseth et. al [16] developed a model that considers different PTDF aggregation schemes based on different nodal weighting schemes. Based on the tests performed, they concluded that the type of weighting scheme does not significantly impact the simulation results. In this work, we discuss the mathematical derivation of PTDFs from network parameters and analyze the performance of the considered PTDF aggregation schemes.

[1]The maximum value of transmission capacity which can be offered to the market with out affecting system security reduced by the reliability margin is referred to as Net Transfer Capacities (NTC) [11].

IV. Mathematical Formulation

A. Determination of PTDFs from line reactances

In a given system with $N+1$ nodes and N_b branches, the dimension of the admittance matrix, $\boldsymbol{\beta}$, is $N \times N$. Besides, the flow matrix, $\boldsymbol{\beta}_f$ has a size of $N_b \times N$. Considering a DCOPF, all but the reference node will have unknown angles, δ. If $\underline{\delta}$ refers to $N \times 1$ vector of angles, the following relations hold.

$$\boldsymbol{\beta}\underline{\delta} = \underline{P}_{inj} \tag{1}$$

$$\boldsymbol{\beta_f}\underline{\delta} = \underline{P}_f \tag{2}$$

Where $\underline{P}_{inj}$ and $\underline{P}_f$ refer to the vector of net nodal power injection and branch flows, respectively. The net nodal injection is the sum of all generation connected to the node added with injections from HVDC cables, which can be positive or negative depending on the direction of flow, and reduced by the load connected to the given node. Combining (1) and (2), (3) gives the relationship between nodal injections and branch flows and the PTDF matrix, $\boldsymbol{\Phi}$ is given by (4).

$$\boldsymbol{\beta}_f\boldsymbol{\beta}^{-1}\underline{P}_{inj} = \underline{P}_f \tag{3}$$

$$\boldsymbol{\Phi} = \boldsymbol{\beta}_f\boldsymbol{\beta}^{-1} \tag{4}$$

$\boldsymbol{\Phi}$ is an $N_b \times N$ matrix and is defined for each branch in relation to nodal injection. An element of the PTDF matrix, $\phi^i_{l,n}$, equals to the fraction of flow along a branch connecting nodes l and n for a unit injection in node i and withdrawal in the reference node (*cf.* Fig. 1). Equation (3) is rewritten compactly in (5).

$$\boldsymbol{\Phi}\underline{P}_{inj} = \underline{P}_f \tag{5}$$

B. Nodal to Zonal PTDF Aggregation

The aggregation is done in such a way that the system is divided into zones where each zone includes a number of nodes. The generators and loads in each zone are then connected to the aggregated node (zone). Furthermore, inter-zonal transmission lines are aggregated and represented by a single equivalent inter-zonal line. An important task in achieving accuracy with a node aggregation approach is identifying nodes belonging to a given zone and the number of zones required [17]. This is because of the underlying assumption taken while aggregating that no congestion occurs within a given zone.

To calculate PTDFs at zonal level, nodal PTDFs are aggregated. The detailed PTDFs within each zone are weighted according to a given scheme. Some possible schemes are equal weighting factor in all nodes (pro rata), net active power injection, nodal production, remaining capacity in generators, and change in power injection from previous iteration [16]. Of these schemes, the predetermination of the aggregated PTDFs is possible using the first scheme only. For the other schemes the PTDF should be recalculated before every DCOPF computation.

In this work we compare three PTDF aggregation schemes.

- *Scheme 1:* assigns equal weighting factor for all nodes within a given zone, *i.e.* given N_n^z nodes in a zone the weight of each node will be $\frac{1}{N_n^z}$.
- *Scheme 2:* assigns the nodal weighting factors from the net injections (generation minus load) in a given zone. Hence, the nodal injections should be known or estimated.
- *Scheme 3:* assigns the nodal weighting factors from the injections due to only generation in a given zone. Hence, the nodal generation should be known or estimated.

In actual conditions, the injections for *Scheme 2* and generations for *Scheme 3* are not known ex-ante, thus should be forecasted. For this analysis, we consider two versions: one with perfect foresight of nodal generation and injection, hence using the result of the nodal DCOPF results for the zonal DCOPF analysis. In the second version, we consider a case with wind and load forecast uncertainty and run the zonal DCOPF. Considering the sample network in Fig. 1(a) and its aggregated representation in Fig. 1(b), (6) represents the zonal PTDF between zones z and y for an injection in zone z.

$$\psi_{z,y}^z = \psi_{l,n}^z + \psi_{m,o}^z \tag{6}$$

Where:

$$\psi_{l,n}^z = w_i\phi_{l,n}^i + w_j\phi_{l,n}^j + ... + w_m\phi_{l,n}^m \tag{7}$$

As can be seen from (7), the aggregated PTDF for one of the lines connecting zones z and y for an injection in z

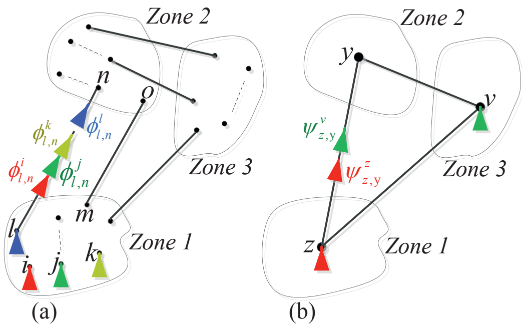

Fig. 1. (a) Graphic description of node level PTDFs. Each colored arrow along line *l-n* corresponds to the PTDF on the given line for a unit injection in a given node (represented by the same colored arrow) and withdrawal at a reference node (not shown in the figure). (b) PTDFs aggregated to zones

is given as the sum of the weighted average of the nodal PTDFs in zone z for a flow along the specified line. Based on the weighting scheme, the nodal weighting factors in a given zone may vary from each other. Besides the weighting factor for a given node might also be time dependent.

With this, we get a zonal PTDF matrix $\mathbf{\Psi}$ with a dimension of $N_z \times N_t$. Where $N_z + 1$ is the number of zones and N_t is the number of inter-zonal connectors. In practical systems, each zone often contains a large number of nodes that a node within a given zone is selected as a reference node, avoiding the need to specify a reference zone. Thus in such systems, the PTDF matrix have a size of $(N_z + 1) \times N_t$. Helseth *et al.* [16] use this approach in their analysis. Given a perfect foresight of nodal injections, *Scheme 2* gives identical results as the nodal DCOPF analysis (*cf.* Section VI-A).

For the version where we have forecast uncertainty, the inter-zonal flows are calculated as follows. For *Scheme 1* and *Scheme 2*, the flows are calculated in (8).

$$\mathbf{\Psi}\underline{\boldsymbol{P}}_{inj}^z = \underline{\boldsymbol{P}}_f^z \tag{8}$$

Where $\mathbf{\Psi}$ represents the respective zonal PTDF matrix, and the net injection and the inter-zonal flow vectors are represented by $\underline{\boldsymbol{P}}_{inj}^z$ and $\underline{\boldsymbol{P}}_f^z$ respectively. For *Scheme 3*, (8) is modified by adding an offset vector $\underline{\boldsymbol{F}}^0$ in (9).

$$\mathbf{\Psi}\underline{\boldsymbol{P}}_{inj}^z + \underline{\boldsymbol{F}}^0 = \underline{\boldsymbol{P}}_f^z \tag{9}$$

Considering the weighting factors due to only generation, the effect of the loads in the nodal injections is ignored affecting the accuracy of the zonal PTDF. As a result, flow calculations like (8) result in large deviations. To compensate for this, we add an offset vector $\underline{\boldsymbol{F}}^0$ which is obtained by subtracting the zonal from the nodal flow results in this scheme for the reference scenario (*i.e.*, $\underline{\boldsymbol{F}}^0 = \underline{\boldsymbol{P}}_f^z[Nodal] - \underline{\boldsymbol{P}}_f^z[Zonal]$). For the purpose of obtaining $\underline{\boldsymbol{F}}^0$, (8) is used to calculate the zonal flow for *Scheme 3*. In other words, the negative of the flow error due to aggregation according to *Scheme 3* for the reference scenario employing (8) is used as an offset, $\underline{\boldsymbol{F}}^0$.

V. Case Study

We applied the PTDF aggregation methodology to the IEEE 30-bus test system, shown in Fig. 2. The system has 30 nodes, 41 branches, 6 generating units, and 21 loads. The data is obtained from [18]. The generation cost function is approximated with linear interpolation, thus each unit is described by a marginal cost and a fixed cost for simplification. For each generation unit, the maximum and minimum generation capacity is given. Each line is represented with a maximum transmission capacity limit and an admittance. Besides, to consider the effect of wind and load forecast uncertainty in PTDF aggregation, (*cf.* Section IV-B), a modified version of the IEEE 30-bus test system is considered.

Node 1 is taken as a reference node in the original system and a reference zone in the aggregated system. The system is

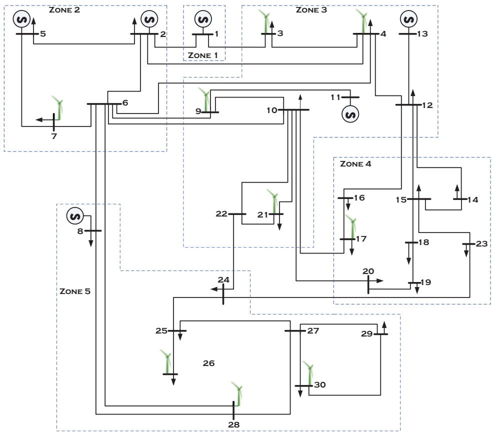

Fig. 2. Representation of the modified IEEE 30-bus test system taken from [19]. The original IEEE 30-bus test system is without wind power plants [18].

aggregated into 5 zones. In the European context, the division normally follows a mixture of country borders and system bottlenecks. However, we did not try to optimize the split into zones for the analysis, and we do not consider that to have influence on the results as the system is small and uncongested. The PTDF matrix of the original system is 41 × 29. The aggregated system has 5 zones and 7 interconnectors; hence represented by a 7 × 4 zonal PTDF matrix.

VI. Results and Discussion

Given the parameters, we run a Mixed-integer Programming (MIP) optimization problem to minimize the total costs satisfying the set of constraints. We use GAMS with the CPLEX solver for the analysis. We perform DCOPF for the 30-bus system and the aggregated equivalents performed by making use of the three PTDF aggregation schemes. In the following, we compare the DCOPF results of the three PTDF aggregation schemes in relation to the original system representation based on generation, inter-zonal flows, and total cost with the following considerations.

(A) Under perfect foresight of nodal generation and injections using the original IEEE 30-bus test system and,
(B) Under uncertainty due to wind and load forecasting errors using a modified IEEE 30-bus test system.

A. PTDF aggregation with perfect foresight of nodal generation and injection

We consider only *Scheme 1* and *Scheme 2*. *Scheme 3* is not considered because there is no generation in zone 4.

1) Generation: The normalized mean generation deviation as a result of using the equivalent network representation is calculated in (10) with i referring to the respective scheme.

$$err^{Scheme\ i}_{\%gen} = \frac{1}{N_g}\sum_{g}\frac{\left|p^{Scheme\ i}_{g} - p^{30-bus}_{g}\right|}{p^{30-bus}_{g}} * 100\% \quad (10)$$

N_g refers to the number of generating units; where as p_g^{30-bus} and $p_g^{Scheme\ i}$ stand for the output of each generating unit in the nodal DCOPF and the zonal DCOPF calculation for the respective PTDF aggregation scheme respectively. *Scheme 1* results in a very low deviation and *Scheme 2* gives identical result as the nodal representation (*cf.* Table I). The zero deviations of *Scheme 2* are consistent with the discussion in Section IV.

2) Flows: In the case of the 30-bus consideration, the flow along the lines connecting two given zones is summed to get the inter-zonal flows. In the zonal equivalents, on the other hand, the inter-zonal flows are directly obtained from the DCOPF calculations. The average inter-zonal flow deviations are evaluated as a percentage of the inter-zonal maximum capacity, $\overline{Tx}_z$, as in (11) for the respective scheme i. As some of the inter-zonal flows are very low, representation of errors in relation to the maximum line capacity gives a better indication.

$$err^{Scheme\ i}_{(\%fl)} = \frac{1}{N_{fl}}\sum_{flows}\frac{\left|p^{Scheme\ i}_{fl} - p^{30-bus}_{fl}\right|}{\overline{Tx}_z} * 100\% \quad (11)$$

N_{fl} refers to the number of inter-zonal connectors, where as p_{fl}^{30-bus} and $p_{fl}^{Scheme\ i}$ represent the inter-zonal flows in the 30-bus and the respective aggregated system representations respectively. As expected, the DCOPF calculations on the aggregated system employing *Scheme 2* result in identical inter-zonal flows as the DCOPF on the 30-bus representation. On the other hand, *Scheme 1* results in average inter-zonal flow error of 6.4% (*cf.* Table I).

TABLE I
Normalized mean deviation for the aggregation schemes compared to non-aggregated representation [%]

	Scheme 1	*Scheme 2*
Generation	1.8	0
Flows	6.4	0
Cost	0.12	0

3) Total Costs: The total costs in the 30-bus system is USD 1163.7. Similarly the total cost resulting from the PTDF aggregation based on *Scheme 1* is USD 1165.1, which accounts for a deviation of just 0.12%.

B. PTDF aggregation with wind and load forecast uncertainty

In real systems we do not have a knowledge of the nodal injections ex-ante, which instead must be based on forecasts, that essentially are uncertain. To address this issue, we consider a modified IEEE 30-bus test system that incorporates 76.5 MW wind capacity equally distributed between nodes 3, 4, 7, 9, 17, 21, 26, 28, 30 [19]. To balance out the increased generation capacity, each load is scaled up by 25%. Wind is added to create forecast errors, representative of a real system today.

To account for the forecast uncertainty, we generate 1000 scenarios of wind power generation and nodal loads. The wind output scenarios and nodal loads are uniformly distributed around the expected output in the range of $\pm 25\%$ and $\pm 5\%$ respectively. No correlation is considered between nodes for the load forecast and wind power scenarios nor between load and wind forecast scenarios[2]. To calculate the zonal PTDFs for *Scheme 2* and *Scheme 3*, the injection values for the reference scenario are taken and the same PTDF matrices are used for all scenarios, based on the expected values for load and wind generation. The procedure is illustrated in Fig. 3. Following this, the DCOPF is run according to (8) and (9).

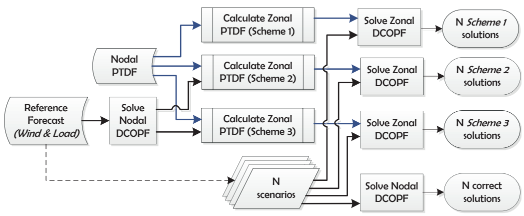

Fig. 3. Handling the PTDF aggregation and subsequent DCOPF with N forecast scenarios for the schemes considered

In Fig. 4 and Fig. 5, the normalized mean absolute errors (NMAE) of generation, total cost, and inter-zonal flows for each PTDF aggregation scheme compared to the nodal representation are presented[3]. Similarly, the NMAE over all scenarios are shown in Table II. It can be seen from Fig.

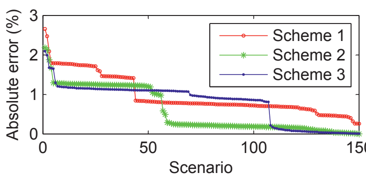

Fig. 4. Generation NMAE sorted in descending order (%)

4 that the generation NMAE are higher for *Scheme 1* in most scenarios and lower in some compared to *Scheme 2*. *Scheme 3*, in contrast, results in errors that are in between the other two schemes. As can be seen from Table II, *Scheme 2* gives the least generation errors followed by *Scheme 3*.

The sorted total cost NMAE are presented in Fig. 5. The NMAE in *Scheme 3* are slightly higher than *Scheme 2*, where as *Scheme 1* registers the least errors. It seems slightly peculiar that *Scheme 1* results in the best cost estimate while it gives worst flow and generation representation. Closer scrutiny reveals that this is not a general result, but is caused by the

[2]In reality, a geographic correlation between nodes can be drawn for a given wind forecast scenario. However, the intention here is only to generate wind forecast errors and nodal correlation is not considered for the forecasts.
[3]1000 scenarios are generated but only the first 150 scenarios are used for display purposes.

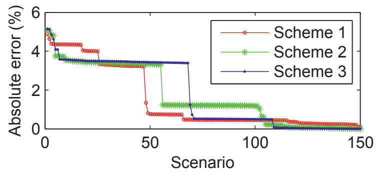

Fig. 5. Total cost NMAE sorted in descending order (%)

TABLE II
SCENARIO AVERAGE NMAE (%)

	Scheme 1	*Scheme 2*	*Scheme 3*
Gen.	0.96	0.58	0.78
Flow	8.84	4.46	3.59
Cost	1.57	1.89	1.98

specific properties of the test case, related to which generators are committed in each scheme.

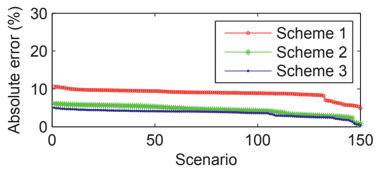

Fig. 6. Inter-zonal flow NMAE in relation to maximum transmission capacity sorted in descending order (%)

Unlike the cost and generation deviations, the inter-zonal flows show a distinct non-overlapping error pattern. The scenario NMAE for the average inter-zonal flows are the highest for *Scheme 1* and the lowest for *Scheme 3*. This can also be seen in the sorted errors in Fig. 6.

In Fig. 4, breaks are observed in the sorted errors which is explained as follows. Because of the binary variables, some units are running in some scenarios and turned off in other scenarios. Besides, for a given Scenario, some unit(s) could be running when considering *Scheme 2* where as they could be off in the base case. Thus, in the case where a unit is off, another unit, g, should be generating more to account for the power that otherwise should have been provided by the turned off unit. As a result, when comparing the scheme and the base case for unit g, there sometimes results an error value equal to at least the minimum generation capacity of the unit not running in one of the schemes. Hence, this break occurs in the error curve for that unit which subsequently affects the average generation error curve. The breaks in Fig. 6 and Fig. 5 are the direct consequences of this occurrence.

The results also show that *Scheme 2* and *Scheme 3* give better results compared to *Scheme 1*, specifically for inter-zonal flows and generation. From the results in Section VI-A, with perfect knowledge of the nodal injections, *Scheme 2* represents the original nodal system perfectly. Even under uncertainty, however, *Scheme 2* gives a good representation of the system. In general, the load and wind forecast errors are relatively small compared the total load and generation capacity. Besides, the forecast errors in wind and load are uniformly distributed that there are netting (cancelation) of deviation effects. Hence, for small deviations from the reference value, *Scheme 2* fairly represents the original system.

Scheme 3 gives the least inter-zonal flow errors. This is predominantly due to the introduction of the offset vector, $\underline{\boldsymbol{F}}^0$, into the flow calculation in (9). A check on the scheme without applying the offset vector resulted in *Scheme 3* giving very large deviations compared to the other two schemes. It should be noted that it is very crucial to have a good estimation of $\underline{\boldsymbol{F}}^0$ for *Scheme 3* to be as effective.

Scheme 1 gives the largest deviations between the nodal and the zonal calculations. This is to be expected given that this scheme employs a simple averaging of the nodal PTDFs in a given zone to obtain the zonal PTDFs. It, however, allows the predetermination of the zonal PTDFs and is always numerically stable. Although not observed in the modified case study, *Scheme 2* and *Scheme 3* can face numerical instabilities when the sum of net injections or net generation in any given zone is zero. The zones in reality, however, which often represent country borders, encompass large number of nodes with multiple generating units within, rendering the probability of such scenario to be low.

VII. Conclusion

We test three PTDF aggregation schemes under two conditions. The first scheme is based on the use of equal sensitivity for every node in a given zone for the aggregation. The second scheme determines the nodal sensitivities based on the net nodal injection in relation to the zonal injection. The third scheme uses the nodal injection due to generation to determine the nodal weighting factors. The first scheme is the simplest as it allows the predetermination of the zonal PTDF values. The second and third schemes on the other hand rely either on historical net injection (generation) data or forecasted nodal injections (generation), thus becoming time dependent inputs that need to be updated for every calculation.

Based on generation, inter-zonal flows, and total cost, we analyze the deviation of PTDF aggregation of the three proposed schemes compared with the DCOPF calculation on the node based PTDFs for the IEEE 30-bus test system.

With perfect foresight of the net injections, the errors with the PTDF aggregation based on *Scheme 1* are very low. As expected, zonal DCOPF calculation based on *Scheme 2* gives identical results as the nodal DCOPF calculation. In the case with wind and load forecast uncertainty, the results show that *Scheme 2* and *Scheme 3* give better results than *Scheme 1*, especially with regard to generation and flows. *Scheme 1* results in the least average cost error; however, a closer look reveals that the on/off state of the generators complicates direct comparison of costs. To get good system representation with *Scheme 3*, an offset has to be added to the flow calculations. The results of *Scheme 1* generally deviate more from the nodal representation compared to the other two schemes. Unlike the other two, however, this scheme allows the predetermination of the zonal PTDFs and is numerically stable.

In the end, among others, the choice of a certain scheme for PTDF aggregation depends on the quality of the forecasts, simplicity of the PTDF aggregation, numerical stability of the aggregation method, and accuracy of the results we want to obtain.

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Appendix F

Publication VI

Y. Gebrekiros, G. Doorman, S. Jaehnert, and H. Farahmand, *Balancing Energy Market Integration Considering Grid Constraints*, PowerTech conference, Eindhoven, Netherlands, 29 June-2 July, 2015.

Publication VI

Is not included due to copyright

Appendix G

Publication VII

Y. Gebrekiros, S. Jaehnert, and G. Doorman, *Flow-Based Optimal Transmission Capacity Allocation for Cross-border Reserves Exchange*, Submitted to IEEE Transactions on Power Systems.

Publication VII

Flow-Based Optimal Transmission Capacity Allocation for Cross-border Reserves Exchange

Yonas Gebrekiros, *Student Member, IEEE,* Gerard Doorman, *Senior Member, IEEE,* Stefan Jaehnert

***Abstract*—This paper presents a flow-based modeling approach to optimally allocate cross-border transmission capacity for frequency restoration reserves (FRR) exchange in a sequential market clearance setting. In this market clearance option, FRR is procured first and then followed by the day-ahead (DA) market clearance. This market clearance option is pursued as it is the dominant market clearance option in Europe.**

By considering the Northern European power system, we find that it is profitable to reserve transmission capacity for FRR exchange in this case study. The net benefit is the result of a reduction in FRR procurement cost and an increase in the DA cost due to optimal transmission capacity reservation.

To put the sequential market design in perspective, we also consider optimal transmission reservation by using, the theoretically most optimal, implicit market clearance. In this case, the reserve requirements are implicitly considered as additional constraints to the optimization problem. The flexibility due to short reservation period and efficiency of the market design option contribute to significant total cost reduction offered by this option compared to the sequential with optimal transmission reservation.

***Index Terms*—FRR, Implicit Market Clearance, Sequential Market Clearance, Cross-border FRR Exchange, FBMC.**

I. NOMENCLATURE

Sets

Z,A,T,R,Γ	Set of zones, balancing areas, time periods, balancing regions, and planning periods
$Z_{a/r}$	Set of zones in balancing area a or balancing region r
G, G_R, G_B, G_z	Set of thermal, regulating thermal, base-load thermal, and set of thermal units in zone z
H, H_z	Set of hydro units, hydro units in zone z

Indices

z, y, v	Zone
a, b	Balancing area
r, s	Balancing region
g,h	Thermal, and hydro units
τ	Planning period running from 1 to 365 days
t	Time period running from 1 to 24 hours

Parameters

$MC_{z,g}$	Marginal cost of unit g in zone z (EUR/MWh)
$SC_{z,g}$	Startup cost of thermal unit g in zone z (EUR)
$PL_{z,\tau,t}$	Load level in zone z at t (MWh/h)
$\overline{P}_{z,g/h}$	Maximum generation capacity of thermal unit g or hydro unit h in zone z (MW)
$\underline{P}_{z,g/h}$	Minimum generation capacity of thermal unit g or hydro unit h in zone z (MW)
$\overline{P}^{w/s}_{z,\tau,t}$	Maximum wind power w or solar power s generation capacity in zone z at t (MWh/h)
$FC_{z,g}$	Fixed cost of thermal unit g in zone z when running (EUR)
$WV_{z,h,\tau}$	Water value of reservoir associated with unit h in zone z at the end of τ (EUR/MWh)
$SP_{a,\tau,t}$	Spot price forecast of area a at time t in planning period τ (EUR/MWh)
VLL	Rationing cost (EUR/MWh)
$\overline{R}^{\uparrow/\downarrow}_{z,g/h}$	Maximum up-/downward FRR capacity offer from thermal/hydro unit g/h in zone z (MW)
$c^{\uparrow/\downarrow}_{z,g/h,\tau}$	Upward or downward FRR bidding price of thermal unit g or hydro unit h in zone z for τ (EUR/MW)
$Rr^{\uparrow/\downarrow}_{a,\tau}$	Upward & downward FRR requirement in area a for planning period τ (MW)
$\psi_{z,y,v}$	PTDF from zone z to y for unit injection in zone v and withdrawal at the reference zone
$\overline{P}^{DC/AC}_{z,y}$	HVDC or HVAC capacity between zones z and y (MW)

Variables

$\delta_{z,g,\tau,t}$	Online status of thermal unit g in zone z at t, $\delta_{z,g,\tau,t} \in \{0,1\}$
$u_{z,g,\tau,t}$	$= 1$ if thermal unit g in zone z is started up in time step t, $u_{z,g,\tau,t} = 0$ otherwise
$p_{z,g/h,\tau,t}$	Output of thermal unit g or hydro unit h in zone z at t (MWh/h)
$p^{st/ns}_{z,h,\tau,t}$	Production from hydro unit h in zone z in planning period τ at t from storable inflow st or non-storable inflow ns (MWh/h)
$p^{s/w}_{z,\tau,t}$	Production from solar s or wind w in zone z in τ at t (MWh/h)
$r^{\uparrow/\downarrow}_{z,g/h,\tau}$	Procured upward/downward FRR from thermal unit g or hydro unit h in zone z in τ (MW)
$tr^{(AC)\uparrow/\downarrow}_{z,y,\tau}$, $tr^{(DC)\uparrow/\downarrow}_{z,y,\tau}$	Upward or downward FRR exchange on HVAC and HVDC interconnector, respectively, from z to y for planning period τ (positive is export from z) (MW)
$rp^{\uparrow/\downarrow}_{z,\tau}$	Upward or downward FRR capacity procured in zone z in τ (MW)
$p^{cur}_{z,\tau,t}$	Load curtailed in zone z at t (MWh/h)

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$p^{inj}_{z,\tau,t}$	Injection at zone z at a given time t (MWh/h)
$p^{AC/DC}_{z,y,\tau,t}$	Power flow on HVAC/HVDC line connecting zones z and y at t (positive $z \rightarrow y$) (MWh/h)

II. Introduction

The objectives of the EU energy policy include secure and competitive supplies; renewables and climate change targets of 2020 and beyond; and a significant increase in energy efficiency. One of the instruments to reach these goals is the establishment of an internal electricity market [1]. The Central Western European (CWE) started the development by creating a platform for day-ahead (DA) electricity trading among Netherlands, Germany, Belgium, and France. Since May 2014, a DA market coupling initiative of seven Power Exchanges (PXs) covering 20 countries in Europe [2], the Price Coupling of Regions (PCR), has been in operation.

In addition, there is a significant expansion of renewable energy sources (RES) in the European power system. The RES are predominantly wind and solar whose outputs are intermittent and uncertain, thus challenging the power system operation and planning.

A. Flow-based market coupling (FBMC)

In the electric power network, the flow of power is governed by Kirchhoff's laws; i.e. electric power may take several parallel paths from source to destination of the underlying power exchange and not necessarily the direct contract path. Considering the highly meshed European electric network, for example, a single transaction between Germany and France will partly flow directly between the two countries but also through the Netherlands-Belgium, Switzerland, and Switzerland-Italy corridors. Thus, a spot market clearance model based on Net Transfer Capacity (NTC) tends to be ineffective in highly meshed power networks since the physical reality is not accounted for (*cf.* [3]). The maximum value of transmission capacity which can be offered to the market without affecting system security is referred to as NTC [4].

The EU Guideline on Capacity Allocation and Congestion Management (CACM) [5] require a shift from the current NTC based market coupling approach to FBMC to utilize the transmission system more efficiently [6]–[8]. FBMC uses power transfer distribution factors (PTDF) and is based on a DCOPF formulation. But, instead of modeling the whole grid, only interconnections and Critical Network Elements (CNE) are included. PTDF refers to the line flow sensitivity for given transaction between two nodes.

FBMC is expected to improve quality of market clearing results compared to the NTC based as the physics of power flow is better represented. The quality of the results is defined as the efficient use of cross-border capacity leading to increase in socio-economic benefit. Based on analysis in the CWE region, it is shown in [8] that FBMC can improve the efficiency of the coupled markets compared to the NTC method.

The approach presented in this paper uses a zonal based DCOPF but is not strictly FBMC as we do not consider CNEs other than interconnectors between zones. However, the fundamental principles are the same and the terms are used interchangeably.

B. PTDF aggregation

Although large scale nodal pricing is feasible, *cf.* the PJM market, there is a strong opposition against this approach in Europe. In fact only a few countries have even split their market into price areas, while the majority uses a single price area per country. Thus, the flow-based approach with CNEs can be seen as an attempt to consider the physical grid in the market clearing, without using nodal prices. However, to do so, it is necessary to aggregate the underlying grid.

Various power system reduction and aggregation methods are found in literature [9]–[12]. Commercial softwares such as PowerWorld[1] and PowerFactory[2] also include options to calculate zonal PTDFs based on branch sensitivities. In the PTDF based power system aggregation approach, nodal PTDFs are aggregated into zonal PTDFs that give similar inter-zonal flows. However, estimating the nodal injection factor for a given zonal injection is challenging as the values are not known ex ante and have to be estimated. For an analysis of the Nordic power system, Helseth et al. [11] developed a model that considers different PTDF aggregation schemes based on different nodal weighting schemes. They concluded that the type of weighting scheme does not significantly impact the simulation results. Thus, we employ the "pro rata" based PTDF aggregation scheme for this work, *i.e.* all nodes within a given zone are assigned equal weighting factors. Considering all PTDF aggregation schemes, this scheme reduces the computation effort as it allows for the predetermination of the aggregated PTDFs.

C. Transmission capacity reservation for FRR exchange

The European Network of Transmission System Operators for Electricity (ENTSO-E), defines three types of operating reserves in order of their activation as Frequency Containment Reserves (FCR), Frequency Restoration Reserves (FRR), and Replacement Reserves (RR). For activation in real-time, to counteract imbalances, Transmission System Operators (TSO) reserve FRR for a given period of time prior to the DA market clearance. Currently, the FRR requirements are set per country and mostly procured with in each country. However, if there is going to be exchange of FRR across country borders, transmission capacity must be reserved in order to guarantee the firmness of the reserves. The stance by the Agency for the Cooperation of Energy Regulators (ACER) [13], which is also shared by ENTSO-E, regarding the allocation of transmission capacity for reserves exchange forbids TSOs *"...to reserve cross-border capacity for the purpose of balancing, except for cases where TSOs can demonstrate that such reservation would result in increased overall social welfare and provide a robust evaluation of costs and benefits"*.

By employing different market clearance approaches, studies focusing on the reservation of transmission capacity in Northern Europe have shown that reservation of transmission capacity for reserves exchange can result in total cost reduction to the system [14]–[16]. However, these analyses do not follow

[1] http://www.powerworld.com/
[2] http://www.digsilent.de/

the market clearance sequence followed in Northern Europe, where reserves are procured before the DA market clearance and are usually contracted for a longer period compared with the resolution of the DA market. By developing a model that follows the general market clearance sequence in Northern Europe, the authors of this paper previously assessed optimal transmission capacity allocation for FRR exchange and concluded that reservation can reduce total costs [17]. However, this earlier work was based on the use of NTCs.

D. Implicit market clearance

In the implicit market clearance, the DA market is cleared with the FRR requirements given as additional constraints to the optimization problem. The resolution of the FRR procurement is the same as that of the DA market, 1 hour. Moreover, transmission capacity reservation for FRR exchange is one of the solutions implicitly obtained from the cost minimization problem. Studies demonstrated the substantial benefits obtained when the North American markets switched to implicit markets [18], [19]. The Midcontinent Independent System Operator (MISO), for instance, won an award in 2011 from INFORMS for their market design change from sequential to implicit [20].

E. Organization of this paper

This paper provides the mathematical formulation of a flow-based optimal transmission capacity reservation for FRR exchange in Northern Europe in a sequential market clearance setting. The impact of transmission capacity reservation is assessed against a reference case, where there is no cross-border transmission reservation. For comparison, optimal transmission capacity reservation by using, the theoretically most optimal, implicit market clearance is also pursued.

In Section III, the model is described with the underlying mathematical formulation and afterwards applied to the case study in Section IV. The findings are presented and discussed in Section V and the concluding remarks given in Section VI.

III. Model Description

The model for the sequential market clearance comprises two successive optimization blocks (see Fig. 1), both based on mixed integer programming (MIP). In the first block, each reserve providing unit determines FRR bidding volumes and bidding prices based on spot price forecasts. The second block optimizes the reserve procurement and DA dispatch to allocate optimal transmission capacity for FRR exchange. The resolution of the day-market is t = *1 h* and the planning period, for the bidding and FRR procurement blocks, is τ = *24 h*. To assess the impact of market design variation, an implicit market clearance option is considered for comparison. It runs a flow-based DA clearance where the upward and downward FRR requirements are given as constraints to the optimization problem. Unless specified, the model description and the subsequent equations are for optimal transmission capacity reservation using a flow-based sequential market clearance. A deterministic approach is used. Underlying this choice is

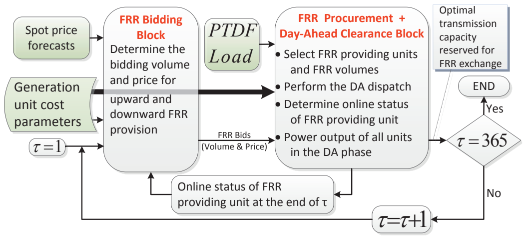


Fig. 1. Sequential market clearance model for optimal transmission capacity reservation (Only major inputs to each block are shown)

the fact that the required reserve quantities are deterministic. The stochastic element lies in the uncertainty of the cross-border price differences, which influence the profitability of the reservation. Although this obviously would have some impact on the numerical results, it is not a principal issue in the present approach, and therefor not included for the sake of computational speed. The model is developed on GAMSIDE using the CPLEX solver.

A. Spot price forecast

Spot price forecasts are essential inputs to determine the FRR bidding prices. In a realistic setting, it is important to have good forecasts in order to obtain the best possible reservation of transmission capacity. The focus of the present paper, however, is to demonstrate the approach, without spending too much effort on good forecasts. The important issue is not to use perfect foresight. A simplified approach is therefore used. For the wind and solar, 24 hour-ahead forecasts are used. The load forecasts: for each weekday but Monday, the corresponding previous day load profile; for Monday the previous week Friday; and for the weekend, load profile of the corresponding day from the previous week are assumed. Taking these values and considering the reserve requirements as constraints, an MIP based implicit DA market clearance with the objective of minimizing total cost is run for 24 hours with 1 hour resolution. The dual values of the power balance for each area are taken as the hourly spot price forecasts. The approach is very simple and we have not tried to develop an advanced forecasting method as the main objective is to obtain a reasonable forecast with some uncertainty.

B. FRR bidding block

Based on the forecast for spot price, an FRR providing unit determines bid prices for FRR provision as a foregone opportunity of profiting in the DA market. A three step approach is applied to determine the bidding prices for the respective FRR provision. The objective of the optimization formulation is for the unit to maximize its profit in each step, as shown in (1). The costs for each unit is the sum of the fuel cost, startup cost and fixed cost, while revenue comes from spot market sales. For *Step 1*, the offered reserve volume is zero, and the whole capacity can be used in the spot market. For *Step 2*, the unit reserves a certain volume for upward FRR, hence less can be used to earn profits in the spot market. For *Step 3*, the unit reserves capacity for both upward and downward FRR, further reducing the revenue in the spot market. The decrease in the respective revenues between the first two steps and the last two steps represent the corresponding cost of providing upward and downward FRR respectively. The volume of FRR a unit can provide should at least correspond to the value a unit can ramp up or down in 15 min. This requirement is according to the ENTSO-E network code on loadfrequency control which states that FRR should be fully activated within 15 min [21]. However, hydro power units can ramp up from zero to full power capacity within 5 minutes. Moreover, different regulating thermal units have varying ramping capabilities depending on the type of fuel. Hence, for all units, a value of 20 % of the difference between the maximum and minimum generation capacity of the unit is considered as the FRR bidding volume in this study. A need to spread the FRR provision to as many hydro units as possible and being an average ramping speed of different reserve providing thermal units, this value is appropriately chosen, (*cf.* [22]). The reason for calculating the upward FRR bidding prices followed by downward is that the former normally have a much higher value. In previous work [23], we found that the order in which bidding prices for hydro units are determined have no impact on the FRR bidding prices.

Objective function:
$\forall g \in G_R,\ a \in A,\ z \in Z_a,\ \tau \in \Gamma,\ i \in \{1,2,3\}$

$$\max \sum_{t \in T} \Big\{ p^{i}_{z,g,\tau,t} \cdot (SP_{a,\tau,t} - MC_{z,g}) - \delta_{z,g,\tau,t} \cdot FC_{z,g} - u_{z,g,\tau,t} \cdot SC_{a,g} \Big\} \quad (1)$$

The objective function in (1) shows the profit maximization approach an FRR providing unit undertakes. Based on the step considered, i in $p^{i}_{z,g,\tau,t}$ takes 1, 2, or 3.
$\forall z \in Z,\ g \in G_R,\ \tau \in \Gamma$

$$c^{\uparrow}_{z,g,\tau} = [B_1 - B_2] \cdot \frac{1}{\overline{R}^{\uparrow}_{z,g}} \quad (2)$$

$$c^{\downarrow}_{z,g,\tau} = [B_2 - B_3] \cdot \frac{1}{\overline{R}^{\downarrow}_{z,g}} \quad (3)$$

Given that B_1, B_2, and B_3 represent the profit for unit g in each respective step, (2) and (3) determine the up- and downward FRR bidding prices respectively. This approach is specific for thermal units. The formulation is modified for hydro units by using the water value instead of the marginal cost of thermal units. Water value refers to the opportunity cost of storing water in a reservoir for future utilization.

C. FRR procurement and DA clearance block

In this block the FRR and DA markets are co-optimized for a 24 hour block to determine the optimal cross-border transmission capacity reservation.

Objective function:
$\forall \tau \in \Gamma$

$$\begin{aligned} \min \sum_{z \in Z} \Bigg\{ & \sum_{g \in G_z \cap g \in G_R} \left(r^{\uparrow}_{z,g,\tau} \cdot c^{\uparrow}_{z,g,\tau} + r^{\downarrow}_{z,g,\tau} \cdot c^{\downarrow}_{z,g,\tau}\right) \\ & + \sum_{h \in H_z} \left(r^{\uparrow}_{z,h,\tau} \cdot c^{\uparrow}_{z,h,\tau} + r^{\downarrow}_{z,h,\tau} \cdot c^{\downarrow}_{z,h,\tau}\right) \\ & + \sum_{t \in T} \Bigg(\sum_{g \in G_z} \Big\{ p_{z,g,\tau,t} \cdot MC_{z,g} + u_{z,g,\tau,t} \cdot SC_{z,g} \\ & \qquad + \delta_{z,g,\tau,t} \cdot FC_{z,g} \Big\} + p^{cur}_{z,\tau,t} \cdot VLL \Bigg) \\ & + \sum_{h \in H_z} \left(WV_{z,h,\tau} \cdot \sum_{t \in T} p^{st}_{z,h,\tau,t} \right) \Bigg\} \end{aligned} \quad (4)$$

The objective function shown in (4) is an MIP problem with an objective of minimizing the total cost resulting from the FRR procurement and DA market within the planning period, τ. It determines the optimal reserve provision from each unit, the power output from each unit for each time step, t, as well as the optimal transmission capacity reservation for FRR exchange for each τ. The total cost is the sum of upward and downward FRR procurement and DA costs. The DA costs comprise fuel, startup, and fixed costs for thermal units, the cost of using water from a reservoir for hydro units, and load curtailment cost. The set of constraints are defined in (5) to (10).
$\forall g \in G_r, t \in T, \tau \in \Gamma, z \in Z$

$$p_{z,g,\tau,t} \geq \delta_{z,g,\tau,t} \cdot \underline{P}_{z,g} + r^{\downarrow}_{z,g,t} \quad (5)$$

$$p_{z,g,\tau,t} \leq \delta_{z,g,\tau,t} \cdot \overline{P}_{z,g} - r^{\uparrow}_{z,g,t} \quad (6)$$

Equation (5) ensures that the minimum output of a regulating thermal unit is greater than the minimum capacity plus the downward FRR provision by the unit. Similarly, (6) limits the maximum output of a unit not to exceed the maximum generation capacity reduced by its upward FRR provision. Similar constraints are used for hydro units with out the equivalent binary variable as the startup cost is considered zero. Moreover, for thermal units that do not provide FRR, i.e. base load thermal units, (5) and (6) are equivalently applied by removing the FRR components from the equations and changing the generation domain to $\forall g \in G_B$.
$\forall \tau \in \Gamma,\ t \in T, z \in Z$

$$\begin{aligned} & \sum_{g \in G_z} p_{z,g,\tau,t} + \sum_{h \in H_z} \left[p^{st}_{z,h,\tau,t} + p^{ns}_{z,h,\tau,t}\right] + p^{w}_{z,\tau,t} \\ & + p^{s}_{z,\tau,t} + \sum_{y \in Z} p^{DC}_{y,z,\tau,t} - PL_{z,\tau,t} + p^{cur}_{z,\tau,t} = p^{inj}_{z,\tau,t} \end{aligned} \quad (7)$$

$$p^{inj}_{z,\tau,t} = \sum_{y} p^{AC}_{z,y,\tau,t} \quad (8)$$

$\forall z, y \in Z,\ \tau \in \Gamma,\ t \in T$

$$p^{AC}_{z,y,\tau,t} = \sum_{v \in Z} (\psi_{z,y,v} \cdot p^{inj}_{v,\tau,t}) \quad (9)$$

Equation (7) defines the zonal injection as the sum of all generation in the zone reduced by the total load in the zone added with the injections from all HVDC lines connected to the zone. Power flow along AC lines is treated differently from flows along HVDC lines because of the controllability of the latter (9). Power injected into zone z should be exported to all zones connected to the zone, which is defined in (8). Equation (9) defines the flow between the zones z and y in relation to the PTDF and injection matrices.

$\forall z \in Z,\ \tau \in \Gamma,\ t \in T$

$$p^{w/s}_{z,\tau,t} \leq \overline{P}^{w/s}_{z,\tau,t} \tag{10}$$

The constraint that the output from RES in a given zone can not exceed the available production is shown in (10) for solar and wind. The output can be lower if there is RES curtailment.

$\forall a \in A,\ \tau \in \Gamma$

$$Rr^{\uparrow/\downarrow}_{a,\tau} = \sum_{z \in Z_a} rp^{\uparrow/\downarrow}_{z,\tau} - \sum_{z \in Z_a} \sum_{y} tr^{(AC)\uparrow/\downarrow}_{z,y,\tau} - \sum_{z \in Z_a} \sum_{y} tr^{(DC)\uparrow/\downarrow}_{z,y,\tau} \tag{11}$$

The upward and downward FRR balance in a given balancing area a for a given planning period, equals the FRR procured in the given area reduced by the export to other areas along the HVDC and AC interconnectors, shown in (11).

$\forall z, y \in Z,\ \tau \in \Gamma,\ t \in T$

$$-\overline{P}^{DC/AC}_{z,y} \leq tr^{(DC)/(AC)\uparrow}_{z,y,\tau} + p^{DC/AC}_{z,y,\tau,t} \leq \overline{P}^{DC/AC}_{z,y} \tag{12}$$

$$tr^{(DC)/(AC)\downarrow}_{z,y,\tau} \leq p^{DC/AC}_{z,y,\tau,t} + tr^{(DC)/(AC)\uparrow}_{z,y,\tau} \tag{13}$$

$\forall z \in Z,\ g \in G_R,\ h \in H,\ \tau \in \Gamma,\ t \in T$

$$r^{\uparrow/\downarrow}_{z,g/h,\tau} \leq \overline{R}^{\uparrow/\downarrow}_{z,g/h} \tag{14}$$

$\forall z \in Z,\ \tau \in \Gamma$

$$rp^{\uparrow/\downarrow}_{z,\tau} = \sum_{\substack{g \in G_z \\ \cap \\ g \in G_R}} r^{\uparrow/\downarrow}_{z,g,\tau} + \sum_{h \in H_z} r^{\uparrow/\downarrow}_{z,h,\tau} \tag{15}$$

The sum of upward FRR and energy exchange from zone z to y at any given time should not exceed the maximum HVDC or HVAC capacity connecting the zones (12). Similarly, the downward FRR exchange between two zones is expressed as a function of the upward FRR and energy exchange between the zones as in (13). As shown in (14), the maximum upward and downward FRR provision should not exceed the respective maximum possible FRR offer from a unit. Equation (15) shows that the upward or downward FRR procured in a given zone is the sum of the contributions from regulating thermal units and hydro units in the zone.

For the implicit market clearance, the objective function contains only the energy cost component in (4) considering the FRR requirements as constraints. On the other hand, the constraints used for the sequential option are also applicable for the implicit.

IV. Case Study

The North European system in the state of 2010, shown in Fig. 2, is considered for the case study. Nodes are aggregated into zones. The generators and loads in each zone are connected to the aggregated node (zone). Furthermore, transmission lines are aggregated and represented by equivalent interzonal lines. A number of zones constitute a balancing area, where each area represents a price area in the Nordic system. For the German system on the other hand, each balancing area represents the control area of the respective TSO. Moreover, the German system is divided into 6 zones; that are grouped along corridors which are likely to be congested. In reality, the German system is a single price area although there is an ongoing discussion about the potential effects of introducing bidding zones [24].

The system contains 27 zones, 40 aggregated AC transmission lines, and 7 HVDC lines. The HVDC interconnections and their maximum capacities are presented in Table I. For the Nordic system we consider 49 aggregated reservoirs, each with an aggregated hydro unit connected to a reservoir. Water values for hydro units, obtained from the EMPS model [25], are used as the equivalent marginal costs. For reliability purposes, $\frac{2}{3}$ of the required FRR must be procured with the local area [26], and the transmission capacity reservation for FRR exchange between balancing regions cap is correspondingly set at 30 % of the capacity. Besides, within a balancing region, up to 10 % of the transmission capacity between zones can be used for FRR exchange. This value corresponds to the average remaining transmission capacity after the DA market gate closure time [27].

The FRR requirement is obtained from the respective TSO of each country and the allocation to each balancing area is done according to the average load. Three cases are considered for the analysis:

- Case 1: Sequential market clearance with no possibility of cross-border reserve procurement. This arrangement is taken as a reference case.
- Case 2: Sequential market clearance where transmission capacity for FRR exchange is optimally allocated for a period of 24 hours. This option is the dominant market clearance option in Europe.
- Case 3: Transmission capacity for FRR exchange is allocated hourly by implicitly clearing the DA market considering the FRR requirements as constraints. This is considered to be theoretically the most optimal market design option.

TABLE I
HVDC interconnection in Northern Europe in 2010

Name	Capacity (MW)	From	To
NorNed	700	Norway	Netherlands
Skagerrak	1000	Norway	Denmark
Konti-Skan	550	Denmark	Sweden
Baltic	600	Germany	Sweden
Great Belt	600	East-Denmark	West-Denmark
Kontek	600	Germany	Denmark
Fenno-Skan	550	Finland	Sweden

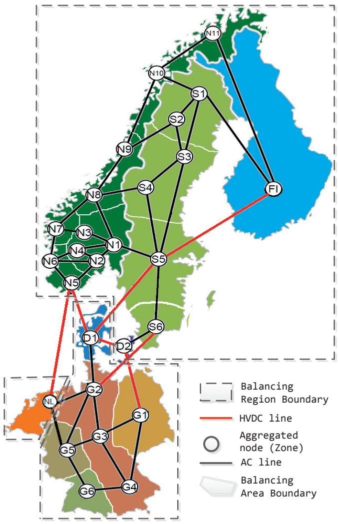


Fig. 2. Northern European system in the state of 2010

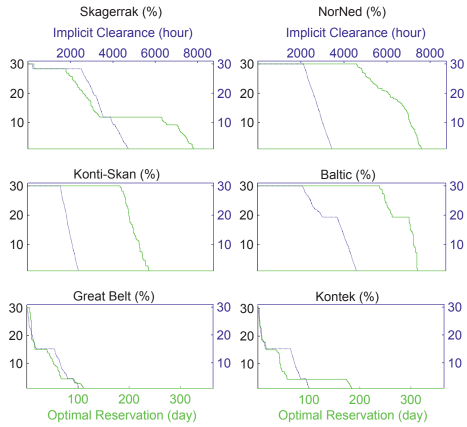


Fig. 3. Optimal transmission capacity reservation for case 2 (green line) and case 3 (blue dotted line) sorted in descending order. The values for case 3 are hourly (top x-axis) and daily for case 2 (bottom x-axis).

V. Results and Discussions

In this section, we discuss the results of the modeling approach applied to the case study. We assess the impact of optimal transmission capacity reservation in a sequential market clearance setting by comparing them with a case of no reservation. In addition, we compare the results with an implicit market clearance option.

A. *Optimal transmission capacity reservation*

The duration curves for optimal transmission capacity reservation on the HVDC connectors are shown in Fig. 3. The curves illustrate the market design impacts of transmission capacity reservation.

As shown in Fig. 3, the duration with no transmission capacity reservation is longer in the implicit market clearance than the sequential option in all corridors. This can also be seen from the percentage durations in Table II. In the sequential market clearance, transmission capacity is reserved for one day where as it is one hour in the implicit case. This means that, in a given day, there could be a number of hours where no transmission is reserved in the sequential option, offering the implicit market clearance more flexibility.

TABLE II
Duration with no transmission capacity reservation (%)

	Skagerrak	NorNed	Konti-Skan	Baltic	Great Belt	Kontek
Sequential	10.7	12.9	34.5	14.8	69.3	49.3
Implicit	46.2	60.8	72.8	47.5	72.0	72.5

The 30% cap on transmission capacity allocation for FRR exchange gives the maximum limit. It can also be seen that the plots also have at least one plateau. These plateaus result from the interaction of the interconnected balancing areas and the limits associated with maximum FRR import and transmission capacity reservation. For the Skagerrak cable, for instance, two plateaus of transmission capacity reservation are observed. One plateau is observed around 12 % and the other one around 28 % of the HVDC capacity. West-Denmark (D1) and the Tennet area of Germany (G2, G3, and G4 in Fig. 2) tend to import as much upward FRR from the Nordic system as possible. Due to a 10 % transmission capacity usage for FRR exchange within a balancing region, maximum FRR export from D1 to Germany is limited to 196 MW. Due to the restriction that $\frac{2}{3}$ of the FRR requirement should come from ones balancing area, D1 can only import a maximum of 87.3 MW. Thus, it imports as much as 283.3 MW from the Nordic system (via the Skagerrak and/or Kontiskan cables). When it imports the maximum 30 % on the Kontiskan cable, which translates to 165 MW, the remaining 118.3 MW should be imported via the Skagerrak cable which gives the 11.8 % plateau. On the other hand, when the import on the Kontiskan cable is zero, all the 283.3 MW should be imported from Southern Norway via Skagerrak cable, which results in the other plateau of 28.3 % reservation. The plateaus on the other HVDC cables are similarly explained by considering the multiple balancing area interactions, transmission reservation restrictions, and FRR procurement limits.

B. *Day-ahead and FRR procurement costs*

For the three cases, the annual DA, FRR procurement, and total costs are shown in Table III. The costs are discussed by highlighting the impacts of market design option and reservation of transmission capacity.

1) Impact of optimal transmission capacity reservation on costs: For the sequential market clearance option, a saving of EUR 18.9 million per year is observed when optimally allocating transmission capacity compared to no transmission capacity reservation for FRR exchange. This total cost reduction is the result of a reduction in reserve procurement cost of

TABLE III
DAY-AHEAD AND FRR PROCUREMENT COSTS [EUR]

	Day-ahead [Billion]	FRR [Million]	Total [Billion]	Improvement from Case 1 [Million]
Case 1	22.74	458.65	23.20	
Case 2	22.78	401.97	23.18	18.87
Case 3	22.55	235.88	22.79	413.34

EUR 56.7 million, but an increase in the DA cost of EUR 37.8 million. The decrease in total FRR procurement is caused by the possibility of procuring cheaper reserves cross-border. This increases the DA costs as the transmission capacity for energy exchange is reduced, comparatively reducing the possibility of cross-border energy exchange. Using the implicit DA market clearance, a total cost reduction of EUR 413.3 million is registered compared to the sequential market clearance option with no transmission capacity reservation. This cost reduction is a result of EUR 222.8 million reduction in FRR procurement cost[3] and EUR 190.6 million reduction in the DA costs.

As can be seen in Fig. 4, the FRR procurement costs are the highest in the period between days 45-120 (Mid February-April). In this period, the reservoir levels in the Nordic system are the lowest, increasing the spot prices, which in turn increase the FRR bidding price, thus increasing the FRR procurement cost in the specified period for the whole system.

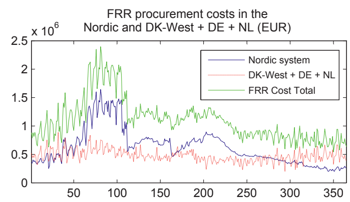


Fig. 4. Time series of FRR procurement costs for the Nordic (blue line), Germany + West-Denmark + Netherlands (dotted red line) system, and total FRR procurement costs for case 2 (EUR).

2) Impact of market design option on costs: Compared to the sequential market clearance option (case 2), a total cost reduction of EUR 394.5 million, which is the sum of EUR 166.1 million reduction in FRR procurement and EUR 228.4 million reduction in the DA cost is obtained when considering the implicit market clearance option (case 3). Making use of implicit market clearance leads to the cost reduction because of the following two reasons.

- The reservation in the sequential approach is based on an uncertain forecast, as a result of the use of unsophisticated forecasting approach, which necessarily does not result in the ex post optimal result.
- In the consideration of the implicit market clearance, the resolution of reserve clearance is taken to be the same as the DA clearance, i.e. 1 hour. This value is 24 hours in the sequential market clearance, meaning that a unit selected to provide reserves should stay online for the whole contract period. As a result, the implicit market clearance offers more flexibility that reduces total costs. Splitting up the reservation period in 2–3 sub periods, would improve the result and reduce the difference between the approaches.

[3]For the implicit market clearance, the FRR procurement cost is approximated by running the implicit DA market clearance with and without FRR requirement and taking the total cost difference.

C. FRR procurement per country and per balancing region

The time series for annual upward and downward FRR procurement in relation to the requirement of each balancing region for the sequential market clearance option are shown in Fig. 5. In general, with optimal transmission capacity reservation (both implicit and sequential market clearances), the Nordic region provides more FRR than the regional requirement, due to the abundance of cheaper hydro resources. This is also the case in the Netherlands, which is mainly because the FRR requirement relative to the peak demand is lower compared to Germany. The Germany + West-Denmark region, on the other hand, provides less FRR than the requirement for the region. This happens because there is a possibility of importing cheaper resources from the other regions. Besides, the reservoir level impact on FRR requirement can be observed from the plots. The low reservoir levels in the Nordic system in the period between days 45-120 increase the FRR bidding prices thus the Nordic system exports less upward FRR (even imports FRR) which is compensated by increasing FRR procurement in the other regions.

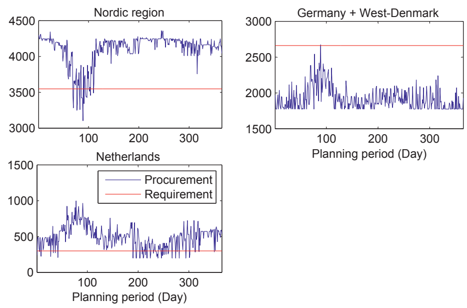
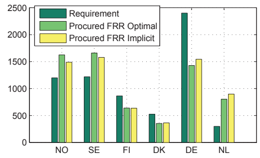
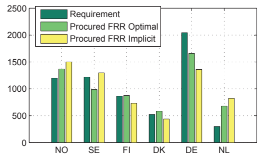


Fig. 5. Time series for upward FRR requirement (red line) versus procurement (blue dotted line) in each balancing region for case 2 (MW).

The annual average FRR procurement per country with optimal transmission capacity reservation using sequential and implicit clearance in relation to the FRR requirement is shown in Fig. 6. In general, a similar trend is observed for FRR procurement for the sequential and implicit clearance in all countries. For upward FRR, more is procured from Norway, Sweden, and Netherlands compared to their requirement. On the other hand, Germany, Denmark, and Finland procure part of their upward FRR requirement from adjacent areas. It can also be seen that the average FRR procurement in the case of implicit clearance is lower in Norway, Sweden and higher in Germany and Netherlands compared to the sequential market clearance. This is the direct impact of the 24 hour vs 1 hour reservation in the sequential and implicit markets respectively.



(a) Upward FRR



(b) Downward FRR

Fig. 6. FRR requirement and average annual procurement per country for case 2 and case 3 (MW).

VI. Conclusion

This paper presents the modeling and analysis of cross-border reservation of transmission capacity for FRR exchange in a flow-based market clearance framework. This is of particular interest in Europe, which is moving towards implementing the flow-based approach.

The paper contributes to the analysis of market design for FRR procurement by laying out a modeling approach to optimally allocate cross-border transmission capacity for FRR exchange in a sequential market clearance setting. This setting is today's dominating market design in Europe, where FRR is procured some time before the clearance of the DA market. The procured FRR are taken into account in the DA market clearance through the reduction in offered capacity by the FRR providers, i.e. the successful bidders of reserve capacity. For comparison, we also consider optimal transmission reservation by using the implicit market clearance, which is considered to be theoretically the most optimal market design option. In this option, the FRR requirements are formulated as additional constraints. The various effects are analyzed in a case study of the Northern European power system.

The results show that, it is profitable to reserve transmission capacity to procure FRR cross-border in the case study. More capacity is reserved with the sequential clearing design. This is due to the flexibility offered by the implicit market clearance as a result of the short FRR procurement period. With the sequential market design, the net annual benefit of reservation of transmission capacity is EUR 19 million, or 4 % of the total reserve procurement cost. The net benefit is made up of a significant reduction in FRR procurement cost, reduced by an increase in the DA cost. Most probably, the benefits will increase with increasing penetration of RES. With the implicit market design, the total cost saving is EUR 413 million or 90 % of the reserve procurement cost. In addition, there will be savings in the balancing energy markets, which are not included in the present analysis.

With respect to the market designs, the annual cost of the implicit reservation model is EUR 395 million lower than the total costs of the sequential option. The cost savings are split rather equally between the DA and reserve capacity markets.

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